National Energy Board

Office national de l'énergie

Canadian Energy Overview

2006

AN ENERGY MARKET ASSESSMENT MAY 2007

Canada

National Energy Board
Office national de l'énergie

Canadian Energy Overview

2006

AN ENERGY MARKET ASSESSMENT MAY 2007

Canada

Cat. No. NE2-4/2006E
ISBN 978-0-662-45359-8

This report is published separately in both official languages. This publication is available upon request in multiple formats.

Copies are available on request from:
The Publications Office
National Energy Board
444 Seventh Avenue S.W.
Calgary, Alberta, T2P 0X8
Email: publications@neb-one.gc.ca
Fax: 403-292-5576
Phone: 403-299-3562
1-800-899-1265
Internet: www.neb-one.gc.ca

For pick-up at the NEB office:
Library
Ground Floor

Printed in Canada

Nº de cat. NE2-4/2006F
ISBN 978-0-662-73702-5

Ce rapport est publié séparément dans les deux langues officielles. On peut obtenir cette publication sur supports multiples, sur demande.

Demandes d'exemplaires :
Bureau des publications
Office national de l'énergie
444, Septième Avenue S.-O.
Calgary (Alberta) T2P 0X8
Courriel : publications@neb-one.gc.ca
Télécopieur : 403-292-5576
Téléphone : 403-299-3562
1-800-899-1265
Internet : www.neb-one.gc.ca

Des exemplaires sont également disponibles à la bibliothèque de l'Office :
Rez-de-chaussée

Imprimé au Canada

TABLE OF CONTENTS

FIGURES

TABLES

CBM	coal bed methane
EIA	Energy Information Administration
EPP	Environmentally Preferred Power
ERCOT	Electric Reliability Council of Texas Inc.
ERO	Electric Reliability Organization
EUB	Alberta Energy and Utilities Board
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
GDP	Gross Domestic Product
IESO	Independent Electric System Operator
IPSP	Integrated Power System Plan
LNG	liquefied natural gas
LPG	liquefied petroleum gas
M&NP	Maritimes and Northeast Pipeline Ltd.
MRO	Midwest Reliability Organization
NGLs	natural gas liquids
OPEC	Organization for Petroleum Exporting Countries
PADD	Petroleum Administration for Defence District
RFC	Reliability First Corporation
SERC	SERC Reliability Corporation
SPP	Southwest Power Pool
U.S.	United States
WCSB	Western Canada Sedimentary Basin
WECC	Western Electricity Coordinating Council
WTI	West Texas Intermediate

LIST OF UNITS

b	barrels
b/d	barrels per day
Bcf/d	billion cubic feet per day
GJ	gigajoule
km	kilometres
kV	kilovolt
m	metres
m^3/d	cubic metres per day
Mcf	thousand cubic feet
MMcf/d	million cubic feet per day
Mb/d	thousand barrels per day
MMb/d	million barrels per day
MMbtu	million British thermal units
MW	megawatt
MW.h	megawatt hour
PJ	petajoules
$ or C$	Canadian dollars
US$	U.S. dollars
Tcf	trillion cubic feet
TW.h	terawatt hour

Foreword

The National Energy Board (NEB or the Board) is an independent federal agency that regulates several aspects of Canada's energy industry. Its purpose is to promote safety and security, environmental protection and efficient energy infrastructure and markets in the Canadian public interest within the mandate set by Parliament in the regulation of pipelines, energy development and trade. The Board's main responsibilities include regulating the construction and operation of interprovincial and international oil and gas pipelines as well as international and designated interprovincial power lines. The Board regulates pipeline tolls and tariffs for pipelines under its jurisdiction. In terms of specific energy commodities, the Board regulates the exports and imports of natural gas as well as exports of oil, natural gas liquids (NGLs) and electricity. Additionally, the Board regulates oil and gas exploration, development and production in Frontier lands and offshore areas not covered by provincial or federal management agreements. The Board's advisory function requires keeping under review matters over which Parliament has jurisdiction relating to all aspects of energy supply, transmission and disposal of energy in and outside Canada.

The NEB monitors energy markets to objectively analyze energy commodities and inform Canadians about trends, events and issues. In the past year, the Board issued a number of Energy Market Assessments (EMAs) on a wide range of energy commodities. In addition, it launched an *Energy Pricing Information for Canadians* section on its website as an additional means to keep Canadians informed on energy market developments.

Annually, the Board does a review of the past year's energy markets. This was previously included in the Board's Annual Report under the heading *Energy Overview*. In 2006, the Board decided to reduce the amount of energy information in its 2006 Annual Report. In its place, a more detailed analysis of energy commodities, markets, supply and trends is published in this standalone EMA, entitled *Canadian Energy Overview 2006*. This report is a summary of major developments in Canada's energy industry in 2006. The Board intends to produce this on an annual basis.

INTRODUCTION

The National Energy Board (NEB or the Board) monitors energy markets to objectively analyze energy commodities and inform Canadians about trends, events and issues. In the past year, the Board issued a number of Energy Market Assessments (EMAs) on a wide range of energy commodities. In addition, it launched an *Energy Pricing Information for Canadians* section on its website as an additional means to keep Canadians informed on energy market developments. The reports and related information can be found on the Board's website at http://www.neb-one.gc.ca.

In 2006, the Canadian energy market witnessed the continuing trend of high and volatile commodity prices. The year started with high crude oil prices and this upward trend continued into the summer months when crude oil reached record highs; however, in the fall and winter both natural gas and crude oil prices plunged because of high inventory levels and above normal temperatures in North America and Europe. By year end, crude oil prices had fallen by 20 percent from the highs reached in July.

Energy continued to be an important factor in the Canadian economy in 2006. The energy industry accounted for almost six percent of Canada's Gross Domestic Product (GDP) and 22 percent of the total value of Canadian exports in 2006. Canada's total energy demand in 2006 was 10,950 PJ, with secondary energy consumption increasing 1.1 percent compared with 2005. Demand for energy increased for space heating, industrial, residential and commercial sectors. Energy demand decreased in 2006 for transportation and non-energy sectors (e.g., feedstocks, greases).

Influenced by global events such as strong world oil demand growth, lack of spare production and refining capacity, and political instability in oil producing regions, crude oil prices averaged US$66 per barrel in 2006, an increase of about 17 percent from 2005. West Texas Intermediate (WTI) began the year at about US$61 per barrel, and reached a record US$78.40 per barrel in July, driven by concerns about the upcoming hurricane season and an escalation of conflicts in the Middle East. By year end crude oil closed at approximately US$61 per barrel, where it began the year.

For the first time in many years, 2006 saw the value of crude oil exports surpass the value of natural gas exports. Net crude oil export revenue which was roughly C$25 billion exceeded the value of net natural gas export revenue of C$24 billion. The gap narrowed significantly with the net value of crude oil exports rising from almost C$16 billion in 2005 to C$25 billion in 2006, an increase of 58 percent. Net natural gas export revenue declined from C$32 billion in 2005 to C$24 billion in 2006 a decrease of 24 percent.

Canadian crude oil production experienced supply interruptions in 2006 in both the oil sands and eastern Canada offshore. Nonetheless, production in Canada increased in the third quarter of 2006 with the return of Terra Nova, Syncrude and the Athabasca Oil Sands Project (AOSP) to full production levels. In 2006, average crude oil production was up six percent compared with 2005, to 416 508 m^3/d (2.62 MMb/d).

Average Canadian natural gas deliverability in 2006 was roughly the same as in 2005 as initial gains in output were gradually eroded over the course of the year by declines in drilling activity. Canadian natural gas consumption in 2006 was down 1.2 percent from the previous year as average temperatures were about 2.4°C above normal. Net natural gas exports (gross exports less imports) in 2006 were 249 million m^3/d (8.7 Bcf/d), about 4.2 percent lower than in 2005, a year when more Canadian natural gas was needed to offset U.S. natural gas supply losses from hurricanes.

The North American market emerged from the mild 2005-2006 winter with above-average levels of natural gas in storage. The recovery of U.S. natural gas supply and abundant storage caused natural gas prices to drift lower during 2006, although concerns of a repeat of the 2005 hurricane season slowed the decline. Prices crept up briefly in July and August as a heat wave across North America increased the use of gas-fired electric power for air conditioning. As the hurricane season passed with no disruptions, natural gas prices fell further. Canadian natural gas prices, measured at the Alberta Energy Company storage facility (AECO-C) hub in Alberta fell in late September to $3.44/GJ, their lowest point since the market bottomed out in 2002, before closing the year at $5.74/GJ.

Canadian revenues from gas exports also saw a year-over-year decrease due to the combination of lower export volumes and prices in 2006. Net export revenues were $24.4 billion, about a 24 percent reduction from 2005's net export revenues of $32.1 billion.

Electricity jurisdictions across Canada continued to focus on adequacy of supply and operating reliability. The trend has been to continue to develop generation sources such as fossil-fuelled generation, nuclear power and hydro electricity, but to also move beyond conventional sources. Ontario, for example, evolved its plan to phase out coal-fired generation. A number of jurisdictions also implemented programs designed to target their specific resource needs. The formation of the Electric Reliability Organization (ERO), authorized under the U.S. Energy Policy Act of 2005, was a major step in beginning to address the operating reliability concerns of the North American grid that came to the forefront following the 11 August 2003 blackout.

Although generation declined slightly, from 595 terawatt hours in 2005 to 586 terawatt hours in 2006, wind turbines, gas-fired generation and planned large hydro developments were dominant additions to future generation portfolios. Domestic demand was adequately met in 2006. Net exports declined 26 percent, from 23.6 terawatt hours in 2005 to 17.4 terawatt hours in 2006, following a strong export year in 2005. Net revenues declined from $1.9 billion in 2005 to $1.3 billion in 2006. Overall, exports were also impacted by milder weather in export markets, while reduced import costs largely reflected the availability of low cost power from U.S. sources.

ENERGY AND THE CANADIAN ECONOMY

In 2006, the energy industry accounted for 5.9 percent of Canada's GDP and directly employed 345,000 people (two percent of the Canadian labour force). Energy export revenue totalled C$99 billion, which accounted for 22 percent of the value of all Canadian goods and services exported in 2006. This energy proportion has continually increased since 2002, when energy exports accounted for 12.5 percent of the value of total exports. Changes in 2006 net energy export revenues (the value of energy exports minus value of energy imports) from 2005 levels varied depending on the commodity. Net export revenues increased for crude oil and coal and coal products by 58 percent and 97 percent respectively, while net export revenues decreased for natural gas and electricity by 24 percent and 30 percent, respectively. In 2006, Canada's net energy export revenue was $50.9 billion, up from $45.4 billion in 2005, a 6 percent increase. This was largely driven by an increase in export revenue from crude oil and NGLs (Figure 2.1). The large increase in net export revenue from crude oil and NGLs enabled net export revenue from crude oil and NGLs to exceed net export revenue from natural gas for a calendar year.

Total energy production increased by four percent in 2006 compared with 2005. Petroleum and natural gas accounted for 38 percent and 37 percent, respectively, of total energy production in 2006. Hydroelectricity production accounted for seven percent of the total, a decrease of 1.4 percent from 2005. Coal production increased by four percent from 2005, accounting for nine percent of total energy produced in Canada in 2006. Strong global demand for thermal coal was expected to continue in 2006, but a balancing of supply and demand is thought to be occurring as Canada's coal exporters settled coking coal contracts for the 2006-07 coal year with slightly lower prices than for the

TABLE 2.1

Domestic Energy Production By Energy Source (petajoules)

	2002	2003	2004	2005	2006[a]
Petroleum[b]	6 049	6 365	6 517	6 404	6 739
Natural Gas	6 660	6 462	6 524	6 373	6 588
Hydroelectricity	1 245	1 198	1 207	1 289	1 271
Nuclear	824	817	986	1 009	1 090
Coal	1 430	1 326	1 476	1 494	1 554
Renewable and Other[c]	631	633	657	681	707
Total	**16 839**	**16 801**	**17 367**	**17 250**	**17 949**

(a) Estimates

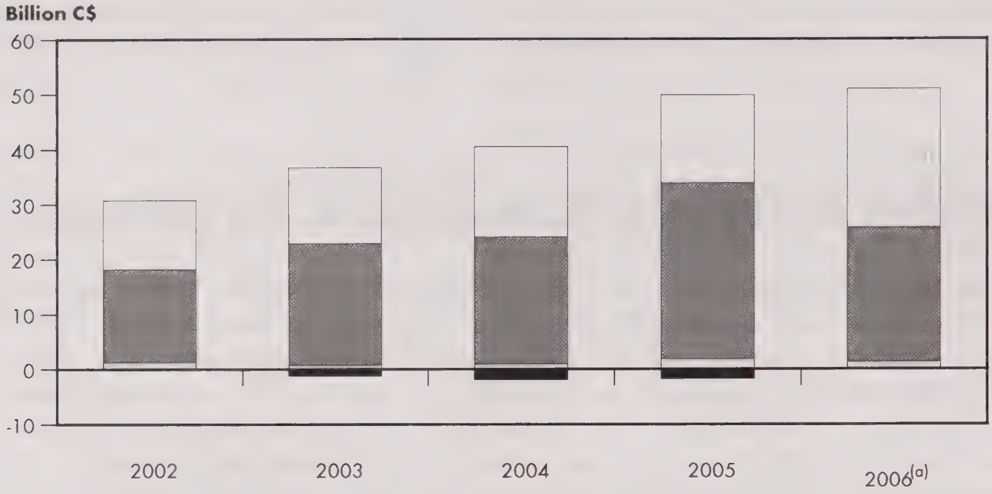
(b) Petroleum includes crude oil and gas plant natural gas liquids (NGLs)

(c) Includes steam, solid wood waste, spent pulping liquor and annual firewood

Source: Statistics Canada, NEB

FIGURE 2.1

Net Energy Export Revenues



Source: Statistics Canada, NEB

TABLE 2.2

Domestic Energy Consumption (a)
(petajoules)

	2002	2003	2004	2005	2006(b)
Space Heating	1 970	2 065	2 032	2 074	2 105
Transportation	2 250	2 242	2 346	2 383	2 357
Other Uses(c)	3 164	3 298	3 312	3 399	3 499
Non-Energy(d)	894	903	1 018	1 020	1 015
Electricity Generation(e)	1 911	1 850	2 029	2 068	1 973
Total	**10 189**	**10 358**	**10 737**	**10 944**	**10 950**

(a) Includes consumption of imported energy

(b) Estimates

(c) Includes energy used for space cooling and ventilation, appliances, water heating, as well as a variety of uses in the industrial sector.

(d) Includes energy used for petrochemical feedstocks, anodes/cathodes, greases, lubricants, etc.

(e) Includes producer consumption and losses as well as nuclear energy conversion requirements.

Source: Statistics Canada, Office of Energy Efficiency, NEB

2005-2006 coal year.[1] Production from renewable and other energy sources increased by 3.8 percent compared with 2005. This was partly due to increased wind energy coming online in several regions, and increases in solar energy and ethanol. Nuclear production increased by eight percent in 2006 compared with 2005.

Preliminary estimates indicate that total domestic energy consumption was flat from 2005 to 2006, but secondary energy demand (the total of the first four categories in Table 2.2) increased by 1.1 percent in 2006. This annual increase is lower than the five-year average annual change of two percent, largely due to the estimated decrease in transportation energy demand. Secondary energy

1 http://www.nrcan.gc.ca/ms/cmy/2005revu/coal_e.htm; a coal year refers to a 12-month period starting on April 1st and ending March 31st.

consumption per capita has increased at an average annual rate of 1.1 percent over the past five years. During the 2002 to 2006 period, Canadian total energy consumption increased on average 1.8 percent per year, compared with the rising average real GDP rate of 2.8 percent per year. This indicates a slight improvement in the energy intensity of the economy (Table 2.2).

> Weather and Energy Demand
>
> With over a third of domestic natural gas consumption directed toward residential and commercial uses, primarily space and water heating, natural gas consumption in Canada is heavily influenced by weather. Six of the warmest ten years on record have occurred within the past ten years.
>
> Environment Canada reported that the 2006 national average temperature was 2.4°C above normal, based on preliminary data. This ranks 2006 as the second warmest year, since nationwide records began in 1948.[2] The heating season of 2005-2006, which runs from November to March, was the warmest seen in over ten years (about seven percent warmer than the five-year average). In addition, 2006 experienced the second warmest summer on record. As a result of this weather, consumption of natural gas was weak over the winter of 2005/06, but higher than normal over the summer months. During such peak cooling times, natural gas is commonly called upon for electricity generation.

Space heating energy demand increased by 1.5 percent in 2006, due to increased activity in the residential and commercial sectors. Weather was not a factor, with heating degree days about seven percent lower than 2005. Industrial use and other residential and commercial uses increased by 3.0 percent and electricity producer consumption and losses decreased by 4.6 percent as electrical generation decreased. Transportation demand decreased by 1.1 percent in 2006 from 2005, possibly in response to sustained higher gasoline and diesel prices or behavioural changes including public transit, working from home and other changes in the freight sector. Non-energy demand was relatively flat, decreasing by 0.5 percent in 2006 from 2005.

2.1 Looking Ahead

In 2007, energy demand will largely be influenced by weather, energy prices and demand for goods and services. Government programs and policies will also affect energy demand not only this year but in future years. In addition, extension of daylight saving time by four weeks in Canada could reduce lighting electricity demand. The federal tax credit for public transit that commenced 1 July 2006 will have been in place for a full year, and its impacts on transportation demand may play a larger role in 2007. As well, 2007 will be the first full year with a GST rate of six percent, which is expected to increase demand for goods and services and may have an impact on energy used by the service and producing sectors. Any program or policy that impacts the personal disposable income levels of consumers and business profits, including other income and corporate tax changes, could impact demand for goods, services and energy to a degree.

Other plans for 2007 include a push toward informing Canadians about sustainable energy choices. Numerous new federal and provincial programs and policies on energy efficiency, energy technology, renewables and transportation come into effect in 2007. Many of these federal programs (e.g., ecoENERGY[3]) are revitalized versions of discontinued older programs and will not

2 Environment Canada – Climate Trends and Variations Annual 2006 http://www.msc-smc.ec.gc.ca/ccrm/bulletin/national_e.cfm

3 http://www.ecoenergy-ecoenergie.gc.ca/index-eng.cfm

significantly impact demand, particularly in the short term. The federal government has stated that emission intensity targets for large industrial final emitters will be in place in spring 2007. New federal incentives (details to be announced) for renewable energy will supplement several provincial renewable incentives, which will influence energy use and fuel mixes. For example, in Ontario, effective 1 January 2007, a wholesaler's annual gasoline sales must be at least five percent ethanol. This could be met by physically blending ethanol with gasoline or through the trading of renewable fuel credits. Other policies under development or not announced at time of writing could affect the demand for energy in 2007.

Upstream Oil and Gas Activity

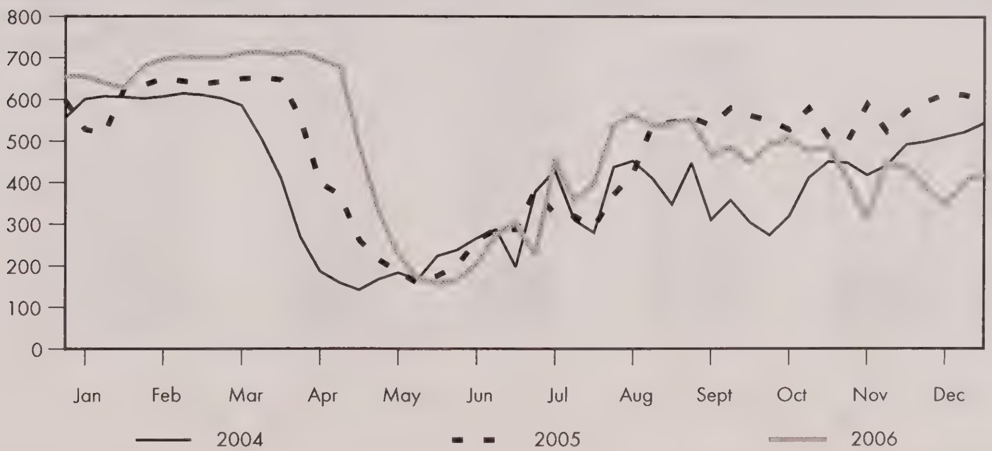
After hurricane-related supply disruptions in 2005, natural gas supply was plentiful in 2006. The North American market emerged from a mild winter with above-average storage levels. Despite high storage levels, North American prices remained relatively strong through the first three quarters of the year. This was largely due to fears of another active hurricane season and the possibility of supply disruptions. When the hurricane season did not materialize as expected, prices fell in late September to their lowest level since 2002. Many companies had hedged portions of their production and so were somewhat insulated from the downturn in prices.

Drilling activity in Canada was extremely high in the first half of the year, relative to previous years. High utilization resulted in shortages of services and materials, reduced drilling efficiency and increases in drilling costs. These contributed to significant escalations in upstream costs of at least 15 percent during the year. By the end of 2006, some analysts estimated full cycle costs for new gas developments were reaching roughly $7.60/GJ ($8.00/Mcf).

Oil prices remained sufficiently strong to accommodate increases in upstream costs, but declining gas prices did not. As a result, oil drilling activity increased in 2006, but gas drilling dropped off significantly in the second half of the year. Drilling budgets were consumed more quickly than anticipated and contributed to the second half slowdown. The strength of drilling activity in the first half of the year in the Western Canada Sedimentary Basin (WCSB) and the slowdown in the second half is indicated in Figure 3.1. On average, there were 473 drilling rigs operating per month in Western Canada compared with an average of 495 in 2005.

FIGURE 3.1

Weekly Active Rigs in WCSB



Source: Nickle's Daily Oil Bulletin

Every year the existing Western Canada natural gas production declines by about 20 percent and new wells are needed to replace this lost production. New wells on average have lower initial productivity than older wells. To fully offset productivity declines, drilling would have to increase by about four percent per year.

As shown in Figure 3.2, just over 22,000 wells were drilled in Western Canada in 2006, virtually the same number as in 2005. The number of oil wells drilled in the year rose by 16 percent to almost 5,600, while the number of dry and other wells declined. Natural gas wells drilled finished 2006 at just slightly below the previous year. As a result of the decline in gas economics relative to oil, the gas share of gas and oil wells drilled eroded marginally from 76 percent in 2005 to 73 percent in 2006.

The size of the Canadian drilling rig fleet increased significantly in 2006 from 764 to 837 rigs. New rigs entering the fleet are likely to be heavily utilized because they are more efficient and because their construction is often underwritten by multi-year term contracts with particular energy companies. Older less efficient rigs in the fleet are more likely to be unused during any drilling slowdown.

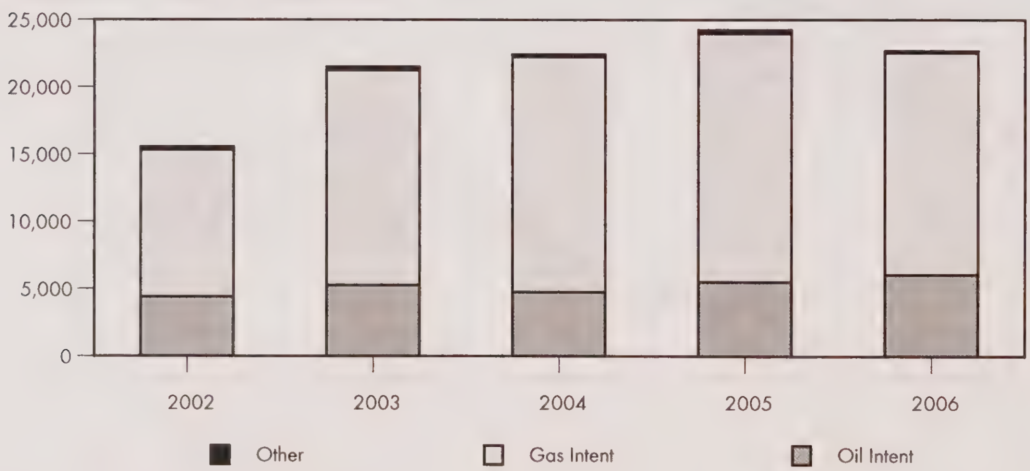
There has been strong growth in the number of drilling rigs with shallow depth capacity (less than 1850 metres) and coiled tubing units in particular. A coiled tubing unit is a specialized drilling rig that uses a long, continuous length of pipe with a downhole mud motor to turn the bit while drilling a well. This differs from a traditional drilling rig that uses jointed pipe with the bit often propelled from the rig floor or top of the drill pipe. These rigs have been purpose-built for drilling Horseshoe Canyon coal bed methane (CBM) wells and shallow gas. With this type of drilling being most heavily impacted by softening gas prices, the utilization of this portion of the rig fleet was below 2005 levels.

There has also been a strong emphasis on adding rigs with the capability to drill deep wells of over 3050 metres in depth. Deep rigs are highly versatile for Western Canada applications in that they can drill deeper wells on the west side of the basin, as well as long horizontal wells for heavy oil, in situ oil sands wells, and Mannville CBM.

Both U.S. gas and oil drilling were maintained at high levels throughout 2006 and contributed to an estimated 4.5 percent increase in U.S. gas deliverability in 2006[4]. Cost inflation also occurred in the U.S., but appears to have been less pronounced than in Canada.

FIGURE 3.2

Number of Wells Drilled in WCSB



Source: NEB Analysis of GeoScout Well Data

4 Oil and Gas Journal Jan 15, 2007, page 28

Competition for land rights remained strong in 2006, with oil sands parcels leading the way. Total land sale payments in Western Canada were $4.19 billion, up 82 percent from 2005. Oil sands parcels represented $1.96 billion or 47 percent of the total. The average price per hectare rose to $761 in 2006 or 33 percent higher than in the previous year. The average price per hectare was distorted by the high price of oil sands parcels at $1,273 per hectare. Land not associated with oil sands was obtained at an average price of $549 per hectare.

In contrast to Western Canada's cash-bonus bid system to allocate land rights, the Frontier regions operate under a work commitment bid system. Exploration licences offshore Newfoundland attracted work bids of $32 million in 2006 or roughly $54 per hectare. Licences in remote areas off Labrador comprised a significant component of the bids and resulted in a significant drop in the average bid per hectare in 2006 compared to the $263/hectare average in 2005. After receiving no bids in 2005, exploration licences in the Beaufort and Mackenzie Delta area jumped to $52 million in 2006. Licensing in the Central Mackenzie Valley also picked up with a 16 percent rise in acreage and a 5 percent increase in the price per hectare.

Seismic survey activity in Western Canada during 2006 was slightly behind the previous year with the average number of active crews down from 15.9 to 14.1, a decrease of 11.6 percent. The industry continues to focus on development programs over exploration as the basin becomes more mature.

Total oil and gas capital expenditures in Canada rose by 17 percent in 2006 to $53 billion. Capital spending associated with oil sands projects jumped by 15 percent to $12 billion. Other spending rose by an estimated 18 percent. A significant portion of the spending increase was consumed by cost inflation and reduced efficiency associated with high industry utilization.

3.1 Looking Ahead

Major companies announced reductions in Canadian drilling budgets for 2007 with the expectation that lower utilization would assist in rolling back some of the service cost increases. Uncertainty regarding prices and high costs pressuring anticipated margins is also an important factor in explaining the reduced budgets. The biggest reductions in planned spending appeared to target CBM and shallow gas programs in central and southeast Alberta. Gas drilling activity in B.C. has also been significantly lower during the 2006-2007 winter than in the previous winter season. It is expected that oil drilling will remain relatively stable in 2007 while the number of gas wells drilled could fall by as much as 10 to 15 percent. Should this occur, gas deliverability could slip by roughly 28 million m^3/d (1 Bcf/d) by the end of 2007. A decline in deliverability of this size would likely cause gas prices to strengthen and lead to stronger drilling in 2008.

Crude Oil and Natural Gas Liquids

4.1 International Markets

In 2006, world crude oil prices followed the trend of 2005 which was marked by continuing high and volatile prices, largely as a result of geopolitical concerns in Iran, Nigeria, Iraq and in other oil producing regions; continuing strong demand in Asia and the U.S.; tight production and refining capacity; and supply interruptions in Alaska.

The continuing impacts of Hurricanes Katrina and Rita were witnessed in 2006, with 27 percent of Gulf of Mexico crude oil production still shut-in. In February, attacks on oil facilities in Nigeria partially suspended export operations, shutting in 54 000 m³/d (340 Mb/d) of production. As well, in a separate incident in Nigeria, onshore and offshore production of about 23 800 m³/d (150 Mb/d) was shut-in. By March, crude oil prices had risen to over $62 per barrel. Prices peaked in July with crude oil rising to a record $78.40 per barrel (intra day high) on concerns that the conflict in Lebanon could spread to other Middle Eastern countries. The countries in the Middle East have over 56 percent of global crude oil reserves and account for over 31 percent of world production. In August, BP Oil Company temporarily shutdown its Alaska Prudhoe Bay oil field, which produces 63 500 m³/d (400 Mb/d) of crude oil or about eight percent of U.S. domestic production, due to extensive pipeline corrosion on approximately 25 km of the pipeline. These events contributed to the high crude oil prices during the summer; however, by October, crude oil prices had dropped 20 percent to below US$60 per barrel. This large decline was due to the market's reaction to a lack of severe hurricane activity in oil producing areas in the Gulf of Mexico, robust petroleum product inventory levels and a softening of demand. In addition, many of the potential geopolitical situations in the Middle East and elsewhere had resulted in little or no impacts on crude oil supply. The average price for 2006 was about US$66 per barrel, an increase of 17 percent compared with 2005. Figure 4.1 illustrates the price of WTI and Brent for the years 2002 through 2006.

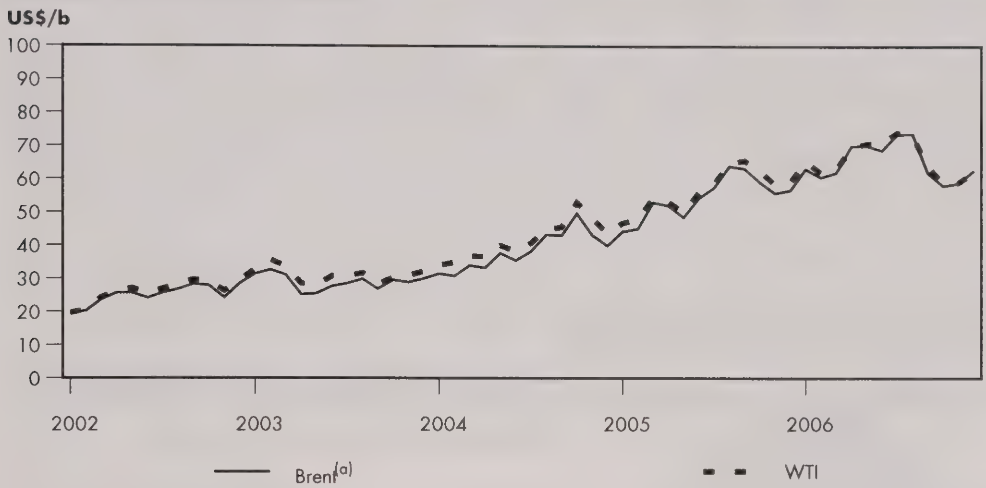
The sharp drop in crude oil prices in the autumn prompted action by the Organization for Petroleum Exporting Countries (OPEC). On 19 October 2006, OPEC agreed to reduce output by 190 500 m³/d (1.2 MMb/d) effective 1 November 2006. This was the first time since April 2004 that OPEC had cut production to prop up crude oil prices. The cut was met with scepticism in the market and had little impact on price. As a result, an additional production reduction of 79 400 m³/d (500 Mb/d) was announced following its 14 December 2006 meeting, effective 1 February 2007. In 2006, Angola applied for membership into OPEC and officially joined as of 1 January 2007. Angola, which produced approximately 238 000 m³/d (1.5 MMb/d) in 2006, is the twelfth member of the group.

4.2 Canadian Oil Production and Reserves Replacement

In 2006, Canadian production of crude oil and equivalent averaged 416 508 m³/d (2.6 MMb/d), an increase of six percent from 2005 levels. This increase reflects the return to production of all three

FIGURE 4.1

WTI and Brent Oil Prices



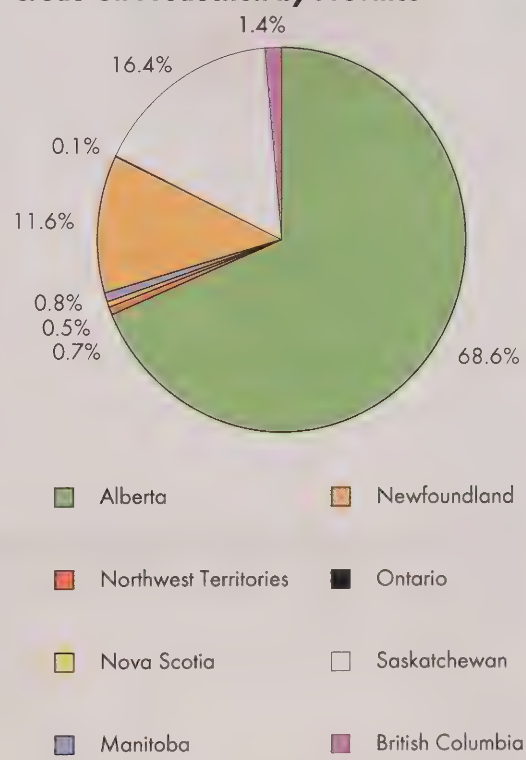
(a) Brent is the common benchmark for European crude oil pricing

Source: IEA

integrated oil sands mining plants, expansions at others and increases in production at the Terra Nova and White Rose fields. Canada's East Coast offshore productive capacity increased by 30 percent, although actual production rose only one percent, due to operational problems at the Hibernia and Terra Nova fields. Figure 4.2 illustrates crude oil production by province.

FIGURE 4.2

Crude Oil Production by Province



Source: NEB

Production offshore Newfoundland and Labrador was 50 547 m³/d (318 Mb/d) in 2006. In Western Canada, crude oil and equivalent supply increased by six percent in 2006. This was largely due to the increase in production at the oil sands. Conventional light crude oil production declined by two percent, reflecting the natural decline of light oil reservoirs in the WCSB. This decline was significantly less than 2005 because strong crude oil prices resulted in increased oil drilling, thereby slowing the rate of decline in the WCSB. Conventional heavy crude oil production levels declined by one percent, in line with the general decline that has developed since the production peak in 2001. Figure 4.3 illustrates crude oil production by type.

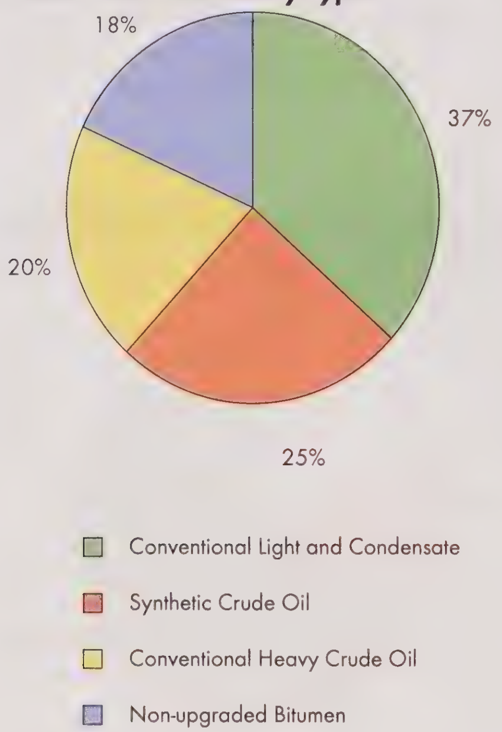
Although total production in 2006 was not up significantly, compared with 2005, production levels in the fourth quarter were strong. In 2007, Canadian crude oil production is expected to increase to 454 200 m³/d (2.9 MMb/d) or 9 percent compared with 2006 levels.

Despite the fact that remaining conventional established reserves are reduced by production each year, new discoveries, extensions to existing pools and revisions to reserve estimates in existing pools usually add to reserves. From 2001 to 2005, cumulative additions of conventional light and heavy crude oil to established reserves replaced 94 percent of production (Table 4.1).

The NEB's estimate of total remaining Canadian conventional crude oil and crude bitumen reserves at year-end 2005 (the last year for which there is mostly complete data available) is 32.5 billion cubic metres (204.9 billion barrels), an increase of less than one percent compared with 2004 (Table 4.2). Estimates of remaining established conventional crude oil reserves in Canada increased by nine percent to 695.6 million cubic metres (4,382 million barrels) for 2005 (Table 4.2). Most of this increase could be attributed to the increase in reserves for the Hibernia Field, offshore Newfoundland, with the remainder coming from Alberta and Saskatchewan. The remaining established crude bitumen reserves decreased slightly to 27.6 billion cubic metres (173.9 billion barrels) reflecting 2005 bitumen production.

FIGURE 4.3

Crude Oil Production by Type



Source: NEB

4.3 Oil Sands

In 2006, the oil sands continued to attract investment from a variety of sources, including multinationals, integrated producers and foreign national oil companies. This attraction is largely being driven by Canada's stable political and investment climate, the huge oil sands resource, and a diminishing number of investment opportunities in other oil producing countries. In 2006, oil sands spending was estimated to be almost $12 billion.

Investment in the oil sands is contributing to strong economic growth in Alberta and spin off opportunities in other provinces of Canada. In 2006, several trade delegations from other provinces visited Alberta to promote their manufacturing and services capability to the oil sands industry. A recent Canadian Energy Research

TABLE 4.1

Conventional Crude Oil Reserves, Additions and Production, 2001-2005 (million cubic metres)

	2001	2002	2003	2004	2005	Total
Additions[(a)]	35	88.1	60.8	66.9	134.7	385.5
Production	84	81	85.6	82.7	78.8	412.1
Total Remaining Reserves	**680**	**690**	**663**	**640**	**696**	
Total Remain Reserves (Millions of Barrels)	**4 279**	**4 342**	**4 172**	**4 027**	**4 382**	

(a) White Rose added in 2002

Source: Provincial Energy Agencies, Offshore Petroleum Boards, NEB

Institute (CERI) study[5], covering the period 2000-2020, indicates that in terms of GDP, employment and government revenues, the direct and indirect benefits of oil sands development accrue to all regions of Canada, with the federal government receiving the largest share of government revenues.

In 2006, bitumen production from mining and in situ operations totalled 194 700 m^3/d (1.2 MMb/d), an increase of 15 percent compared with 2005. In situ bitumen production increased by 10 percent to 76 700 m^3/d (483 Mb/d). Bitumen from mining operations increased by 18 percent to 118 000 m^3/d (743 Mb/d) and upgraded bitumen production increased by 18 percent to 102 800 m^3/d (761 Mb/d) (Figure 4.4).

The oil sands industry continued to struggle with operational problems in 2006. In 2005 Canadian crude oil production declined compared with 2004 because of unscheduled interruptions at the three major integrated mining and upgrading operations. Production rebounded in 2006 despite ongoing

TABLE 4.2

Estimates of Established Reserves of Crude Oil and Bitumen at 31 December 2005 (Million Cubic Metres)

Conventional Crude Oil	**Initial**	**Remaining**
British Columbia(a)	126.9	20.9
Alberta(b)	2 703.7	254.8
Saskatchewan(c)	893.2	197.8
Manitoba(d)	41.5	4.5
Ontario(e)	14.7	1.6
NWT (Nunavut) and Yukon		
Arctic Islands and Eastern Arctic(f)	0.5	0.0
Mainland Territories - Norman Wells and Cameron Hills	52.8	15.7
Nova Scotia - Cohasset and Panuke(d)	7.0	0.0
Newfoundland - Hibernia, Terra Nova and White Rose(d)	299.1	200.3
Total	**4 139.4**	**695.6**
Total (Millions of Barrels)	**26 078.2**	**4 382.3**
Crude Bitumen		
Oil Sands - Upgraded Crude(g)	5 590.0	5 052.0
Oil Sands - Bitumen(g)	22 802.0	22 549.0
Total	**28 392.0**	**27 601.0**
Total in Millions of Barrels	**178 870.0**	**173 886.0**
Total Conventional and Bitumen	**32 531.4**	**28 296.6**
Total Conventional and Bitumen (Millions of Barrels)	**204 947.8**	**178 268.6**

(a) British Columbia Ministry of Energy & Mines and NEB common database.

(b) Alberta Energy & Utilities Board and NEB common database.

(c) Saskatchewan Reservoir Annual 2003 with NEB estimated update

(d) Provincial Agencies or Offshore Boards, NEB estimate for Manitoba

(e) Canadian Association of Petroleum Producers

(f) Bent Horn abandoned 1996

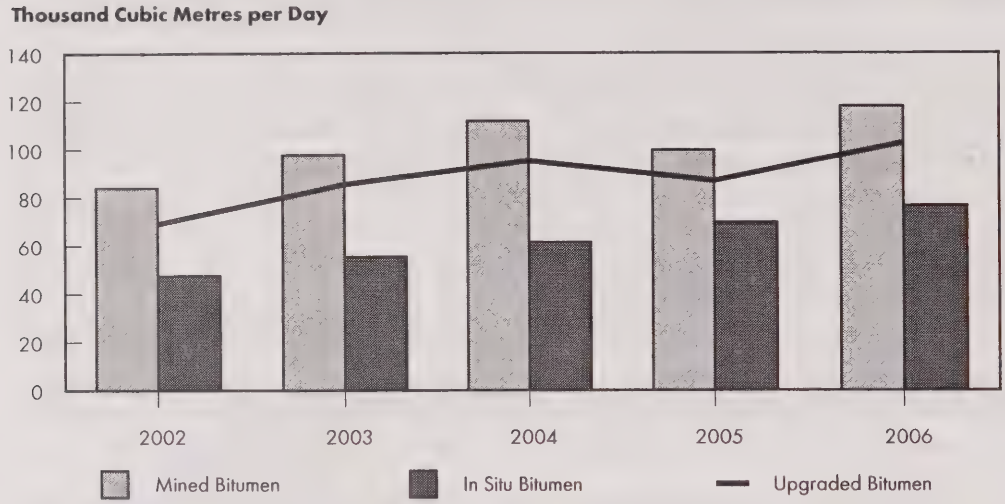
(g) Alberta EUB Reserves 2005 and Supply Outlook 2006-2015

Note: Totals may not add due to rounding

5 The Economic Impact of Alberta's Oil Sands - Canadian Energy Institute Study, No. 110, October 2005

FIGURE 4.4

Crude Bitumen Production, 2002-2006



Source: EUB

problems at the three major integrated mining and upgrading operations. In the first quarter 2006, the Syncrude Coker 8-1 underwent scheduled maintenance reducing its production. In May 2006, the Stage 3 expansion was brought on stream; however, production was suspended soon after because of odourous emissions. It took several months to rectify the problem and bitumen feed was re-introduced to Coker 8-3 at the end of August. This expansion was expected to ramp up production to 55 000 m^3/d (347 Mb/d), and in the fourth quarter 2006, Syncrude's production improved to 53 000 m^3/d (334 Mb/d) from 44 300 m^3/d (279 Mb/d) in 2005. In the first quarter 2006, production at the Athabasca Oil Sands Project was reduced by about 25 percent because of a torn conveyor belt and in the second quarter, planned maintenance was performed at both the Muskeg mine and the Scotford upgrader. The maintenance was expected to last about two months; however, this was extended because additional work was required. In the third quarter 2006, Suncor production was lower because of unplanned maintenance.

4.4 Crude Oil Exports and Imports

Total crude oil exports, including pentanes plus and upgraded bitumen (synthetic crude), are estimated at 285 430 m^3/d (1.8 MMb/d), an increase of 25 830 m^3/d (163 Mb/d) from 2005. The 2006 total consisted of 36 percent light crude oil and equivalent and 64 percent blended heavy crude oil.

Prices remained relatively high throughout 2006. The estimated value of crude oil exports was $39.3 billion, compared with $32.0 billion in 2005. In 2006, the projected average light and heavy crude oil export prices were $448 and $338 per cubic metre ($71 and $54 per barrel), respectively, compared with $423 and $295 per cubic metre ($67 and $47 per barrel) in 2005.

Among other reasons, the light-heavy price differential varies as a function of crude oil market factors. For example, if there is an increase in the supply of heavy crude oil that exceeds demand, the differential will widen. Extraordinary circumstances aside, the differential typically narrows in the summer months due to the higher demand for heavy crude oil during asphalt paving season and then widens again in September.

In 2006, the average light-heavy price differential between Edmonton Par and Western Canada Select (WCS) was $142 per cubic metre ($23 per barrel) compared with $158 per cubic metre ($25 per

barrel) in 2005. The differential was as wide as $219 per cubic metre ($35 per barrel) in February 2006 but subsequently narrowed with the start up of the reversed Enbridge Spearhead pipeline[6]. The pipeline historically operated a south-to-north service, but since March 2006, the pipeline has transported crude oil from Chicago, Illinois to Cushing, Oklahoma and enabled Western Canadian crude oil to access a new market. Similarly, in April, Mobil Pipeline Company's 20-inch Pipeline Reversal Project, from Patoka, Illinois to Nederland, Texas made the first delivery of Canadian crude to the U.S. Gulf Coast. Canadian crude oil is delivered to this line via the Enbridge Pipeline to Lockport, Illinois and the Mustang Pipeline to Patoka, Illinois.

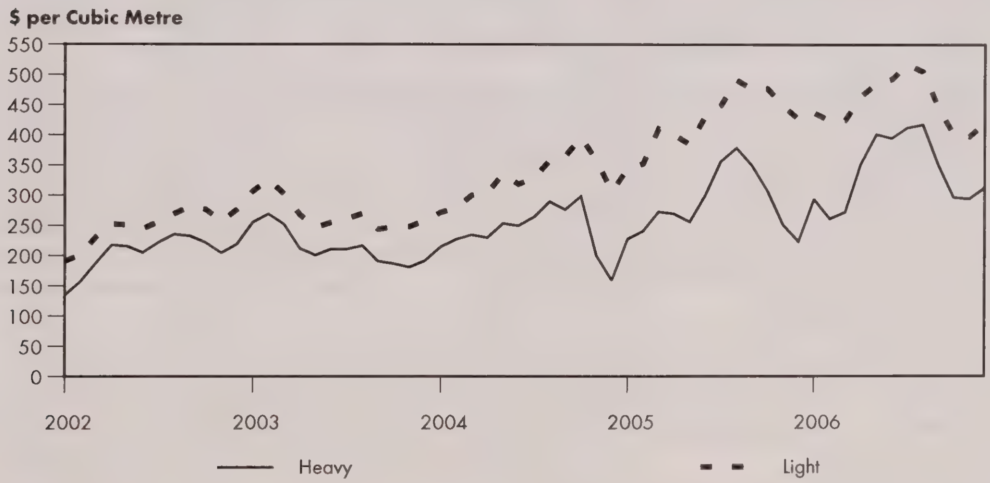
According to the Energy Information Administration (EIA), Canada remained the leading export country to the U.S. for crude oil in 2006, ahead of both Mexico and Saudi Arabia. High oil demand throughout most of the year for diesel, motor gasoline and jet fuel resulted in North American refineries operating at over 95 percent of capacity. The U.S. Midwest is the most significant market for Western Canadian crude oil. The refining centers of Chicago, Illinois, Minneapolis/St. Paul, Minnesota and Toledo, Ohio consumed 49 percent of total Canadian crude oil exports in 2006.

The export market for eastern Canadian offshore production has been primarily the U.S. East Coast. In 2006, 82 percent of the offshore crude oil exports was delivered to the U.S. East Coast (referred to as Petroleum Administration for Defence District [PADD] I), 15 percent to the U.S. Gulf Coast and three percent to foreign markets.

Although Canada is a net exporter of crude oil, much of the requirements of eastern refineries are met with foreign produced crude oil. In 2006, crude oil imports were 136 500 m^3/d (860 Mb/d) and represented 48 percent of total refinery feedstock requirements in Canada. Crude oil requirements for the Atlantic region and Quebec were met by imports as well as volumes of east coast domestic production. Ontario refiners received about 34 percent of their feedstock requirements from foreign sources in 2006. Imports into Ontario decreased by around 20 percent from 2005 due to greater volumes of feedstock requirements being supplied by east coast production in the first part of the year

FIGURE 4.5

Light and Heavy Export Crude Oil Prices



Source: NEB

6 NEB Reasons for Decision, Enbridge Pipelines Inc. RH-1-2005, June 2005.

and use of more competitively priced Western Canadian crude oil. Over one third of all Canadian crude oil imports originated in the United Kingdom and Norway.

4.5 Oil Refining

As of 31 December 2006, there were 19 refineries in Canada with a total refining capacity of 324 500 m^3/d (2.0 MMb/d). The refineries and their locations are in Table 4.3.

During 2006, there were several proposals to build new refineries in the Atlantic Region. If built, they could transform this region into a major processing hub. Refineries in this region are located close to the major petroleum product markets in the U.S. Northeast and have access to foreign crude oil supplies in addition to east coast offshore production. In February, Newfoundland and Labrador Refinery Corporation proposed the construction of a refinery at Placentia Bay, Newfoundland that would have an initial processing capacity of 47 600 m^3/d (300 Mb/d) with the option to expand to 95 200 m^3/d (600 Mb/d). Production is slated to begin in late 2010 or 2011 and study results, revealed near the end of year, indicated that the project would be economically feasible. In late

TABLE 4.3

Refineries in Canada

Company	Location	Capacity (m^3/d)	Capacity (b/d)
Atlantic Canada		**75 200**	**473 800**
Imperial Oil Limited	Dartmouth, N.S	14 000	88,200
Irving Oil Limited	Saint-John, N.B.	44 500	280,400
North Atlantic Refining	Come-by-Chance, Nfld.	16 700	105,200
Quebec		**74 400**	**468,700**
Petro Canada	Montreal	20 700	130,400
Shell Canada Limited	Montreal	20 700	130,400
Ultramar Limited	St. Romuald	33 000	207,900
Ontario		**74 400**	**468,700**
Imperial Oil Limited	Nanticoke	17 800	112,100
Imperial Oil Limited	Sarnia	19 300	121,600
Shell Canada Limited	Sarnia	11 100	69,900
NOVA Chemicals	Sarnia	12 700	80,000
Suncor Energy Products Inc.	Sarnia	13 500	85,100
Western Canada		**100 500**	**633,200**
Consumers Co-operatives Refineries Ltd.	Regina, Sask.	13 500	85,100
Husky Energy Marketing Inc.	Lloydminster, Alta.	4 000	25,200
Imperial Oil Limited	Strathcona, Alta.	28 600	180,200
Moose Jaw Asphalt	Moose Jaw, Sask.	2 400	15,100
Petro Canada	Edmonton, Alta.	21 900	138,000
Shell Canada Limited	Scotford, Alta.	20 000	126,000
Chevron Canada Limited	Burnaby, B.C.	8 300	52,300
Husky Energy Marketing Inc.	Prince George, B.C.	1 800	11,300
Total		**324 500**	**2,000,000**

Source: NEB

October, Irving Oil announced it was exploring the possibility of building a new refinery that could be in operation by 2012 or 2013 to complement its existing 47 600 m^3/d (300 Mb/d) refinery at Saint John, New Brunswick. The Nova Scotia government also attempted to attract an oil refinery to Nova Scotia, which seemed to be less likely after Irving's announcement. However, at the end of the year, a fourth refinery project proposal was announced by a U.S. energy service company to build a refinery either in the Strait of Canso or at Sydney, Nova Scotia.

Not all refineries are configured to process a full range of crude oil types and, therefore, the growing output from the oil sands has become an increasingly important consideration for refiners. Several companies have already indicated that their refineries could be modified to process heavier crude oil. In November, Shell Canada Limited announced that it was exploring the potential of building a new heavy oil refinery near Sarnia, Ontario that could process up to 31 700 m^3/d (200 Mb/d). In addition, Suncor is re-tooling its refinery in Sarnia to further integrate its upstream production with its downstream assets. This would significantly increase the amount of oil sands production refined in Ontario from the estimated 15 900 m^3/d (100 Mb/d) refined in 2006.

Refinery production of main petroleum products in 2006 is estimated at 286 800 m^3/d (1.8 MMb/d), about 3 percent lower than in 2005. Demand for main petroleum products in Canada averaged 273 500 m^3/d (1.7 Mb/d), a two percent decrease from 2005. Refinery receipts of domestic crude oil averaged 150 300 m^3/d (945 Mb/d), essentially the same as in 2005. These refinery receipts were lower than expected with 2006 being the first full year of production from the White Rose field in offshore Newfoundland and Labrador. The potentially higher receipts were offset by unusually high maintenance levels at several refineries and production problems at the Terra Nova field. Commercial inventories of petroleum products in Canada closed the year slightly lower than in 2005.

4.6 Main Petroleum Product Exports and Imports

Canada remains a net exporter of main petroleum products including middle distillates (heating oil, jet fuel and diesel fuel), heavy fuel oil and gasoline. In 2006, exports of main petroleum products and partially processed oil are estimated at 51 500 m^3/d (324 Mb/d), a decrease of eight percent compared with 2005. Refinery outages and a heavy maintenance schedule at many refineries resulted in a decrease in refinery production and subsequently, there were less petroleum products available for export.

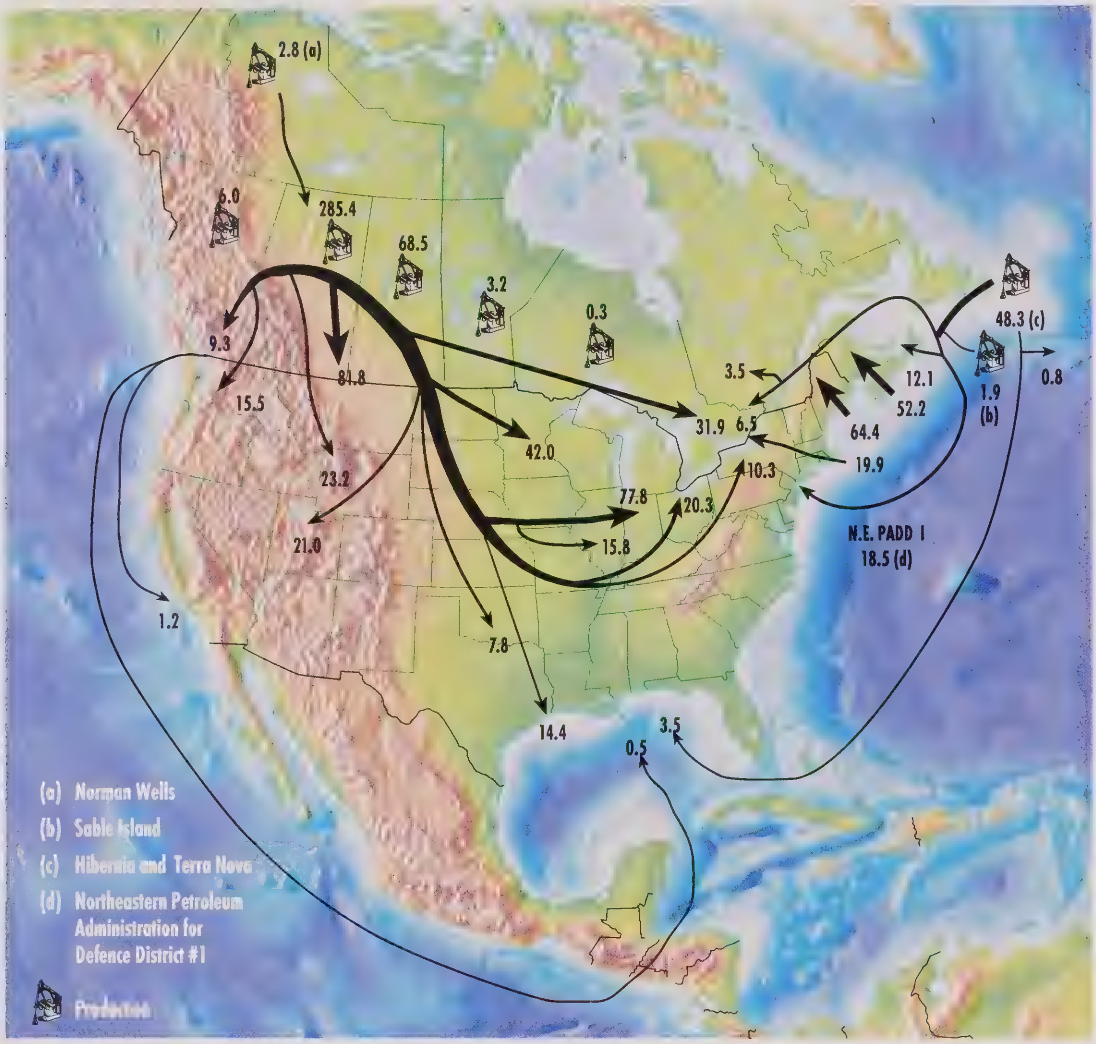
The estimated revenue in 2006 from main petroleum product exports, including partially processed oil was $7.4 billion, up from $6.2 billion in 2005. Strong demand in North America for gasoline and diesel fuel along with refinery outages in both Canada and the U.S. led to high product prices during the first half of 2006. Both gasoline and diesel fuel prices retreated in August prior to the end of the summer driving season, which is the Labour Day holiday in September. High inventory levels for gasoline and distillates in North America put further downward pressure on prices during the fall and winter.

The U.S. continued to be the largest buyer of Canadian produced petroleum products, which accounted for about 93 percent of total U.S. imports. Exports were also made to other destinations, such as, Europe, Mexico and the Caribbean. The U.S. East Coast continued to be the largest market, followed by the U.S. Midwest and the U.S Gulf Coast.

Imports of main petroleum products in 2006 are estimated at 33 800 m^3/d (212 Mb/d), a six percent increase from 2005.

FIGURE 4.6

Crude Oil And Equivalent Supply And Disposition – 2006 (Thousand Cubic Metres Per Day)



Source: NEB

4.7 Looking Ahead

It is expected that geopolitical events, production and refinery disruptions, and weather will be key price drivers in the coming year. 2007 began with crude oil hovering around US$60 per barrel, largely driven by above normal winter temperatures and high inventory levels for crude oil and refined petroleum products in North America. It is expected that recent announcements on refinery expansions and the construction of new refineries in eastern Canada could be finalized in the coming year.

The NEB in its most recent crude oil production forecast has estimated that crude oil production will increase by 9.1 percent compared with 2006; however, crude oil production continues to be plagued by outages in the oil sands region and offshore eastern Canada.

NATURAL GAS

5.1 North American Natural Gas Markets

In 2006, Canada produced about one quarter of the combined natural gas production of Canada and the U.S. Almost 98 percent of Canadian gas is produced from the WCSB with Alberta producing roughly 80 percent. British Columbia and Saskatchewan contribute roughly 16 and four percent, respectively, of the total from the WCSB.

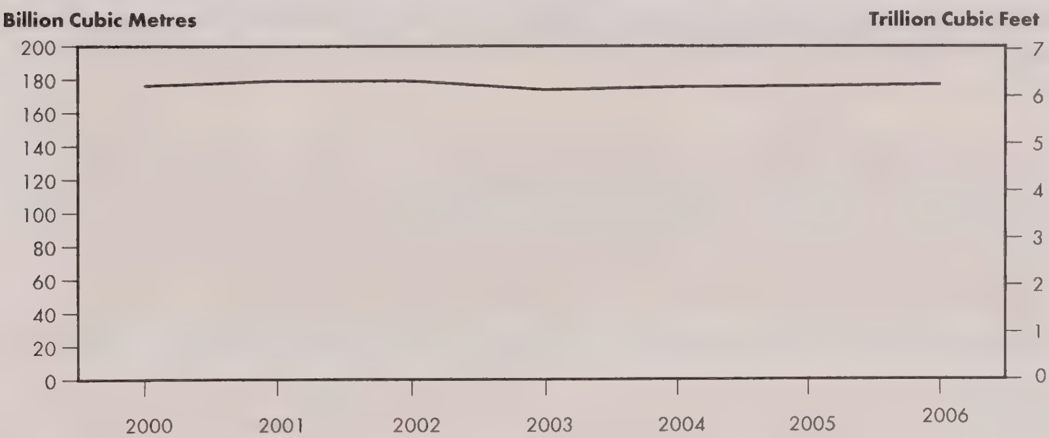
The Canadian and U.S. natural gas markets operate as one large integrated market. This means that events in any region such as changes in transportation costs, infrastructure constraints or weather will have effects on the other regions. Most Canadian and U.S. natural gas production comes from areas roughly following the continental divide, from the Gulf of Mexico to the Northwest Territories. Demand is spread across the continent but is concentrated in densely populated areas and in areas of intense industrial activity. Canadian gas production is connected to the North American gas market through a network of thousands of kilometres of pipelines that allows buyers to purchase and transport natural gas from a number of supply sources across the continent.

5.2 Natural Gas Production

Canadian natural gas production in 2006 averaged 484.8 million m³/d (17.1 Bcf/d), roughly the same as in 2005. Western Canada experienced record drilling activity during the first half of the year followed by a pull back in the second half. Consequently, the number of new gas wells completed in 2006 was just slightly below 2005. By virtue of being in production longer, the greater number

FIGURE 5.1

Canadian Marketable Gas Production



Source: CAPP Statistical Handbook (NEB estimate for 2006)

of wells drilled earlier in the year had a more positive impact on 2006 production than the reduced drilling in the second half of the year. As a result, average production was maintained in 2006 without an increase in the number of new gas well completions.

On the east coast, Sable production continued to vary between about 300 and 400 MMcf/d in 2006. The installation of offshore compression in 2006 is expected to allow Sable gas production to be maintained or increased by producing the remaining gas more quickly. The platform and compression deck was installed in May and connected to the pipeline in September. Final testing and commissioning occurred during the remainder of the year.

Onshore production from the McCully field in New Brunswick is expected to tie into the Maritimes and Northeast pipeline (M&NP) by the second quarter of 2007.

Regarding east coast production, EnCana and the Province of Nova Scotia signed a benefits agreement for the proposed Deep Panuke project. This represents one of many steps that may lead to development of the project, with 2010 estimated to be the earliest that gas production could potentially occur.

North American gas production has recovered to pre-hurricane levels, with increased onshore production in the U.S. Rockies, Texas, Oklahoma and Arkansas regions offsetting continued declines in the offshore Gulf of Mexico. There were no hurricanes in the Gulf of Mexico causing damage to production facilities in 2006.

Liquefied natural gas (LNG) imports into the U.S. increased early in the summer as new LNG production entered the market. As storage filled and prices fell, fully laden LNG tankers were parked in mid-ocean waiting for improved market conditions and were eventually diverted to European and Asian markets. Although the U.S. has a capacity to import over 150 million m^3/d (5.2 Bcf/d) of LNG through five LNG terminals, average LNG imports for the year were 45 million m^3/d (1.6 Bcf/d) or roughly eight percent less than in 2005.[7]

5.3 Natural Gas Reserves

The NEB's estimate of remaining marketable gas reserves at the end of 2005 (the last year for which data is available), is 1 619 billion cubic metres (57.2 Tcf) (Table 5.1). Reserve additions were 250 billion cubic metres (8.8. Tcf) in 2005 and replaced 142 percent of annual production. The rise in remaining reserves reflected increased exploration and improved recovery in known gas fields as a consequence of the strong increase in natural gas prices during 2005. Initial reserves increased in Alberta, British Columbia and Saskatchewan in 2005 while Ontario and frontier regions remained unchanged. With the decline in natural gas prices in 2006, some of the price-related increase in reserves during 2005 may be reversed.

5.4 Canadian Natural Gas Consumption

Approximately one quarter of all energy consumed in Canada is natural gas with estimated consumption in 2006 of about 226 million m^3/d (8.0 Bcf/d), or about 46 percent of Canadian production. Natural gas is primarily consumed in the residential and commercial sectors for space heating, in the industrial sector for process heat, as a building block in chemical production, and to

7 Gaul, Damien and Platt, Kobi, Short-Term Energy Outlook Supplement: U.S. LNG Imports – The Next Wave, U.S. Energy Information Administration, January 2007, pp. 2 & 10, www.eia.doe.gov/emeu/steo/pub/LNG_Jan2007.pdf

produce electricity. In 2006, these sectors consumed approximately 189 million m³/d (6.7 Bcf/d) of natural gas (Figure 5.2). Figure 5.2 also shows that Canadian gas demand for heating, industrial use and electric power generation (included within "direct sales") has been fairly flat, or declining. Growing amounts of natural gas have been seen in the "other" category that includes line pack fluctuation, gas used in the natural gas pipeline system, and lost and unaccounted volumes.

Over one third of domestic natural gas consumption is directed toward residential and commercial uses, primarily space and water heating. Despite continuing growth in residential and commercial

TABLE 5.1

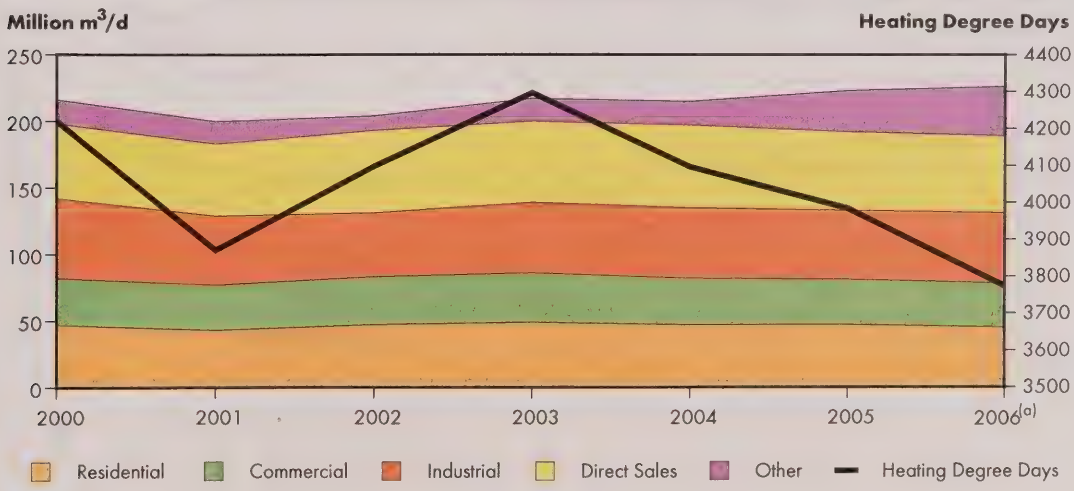
Natural Gas Reserves

(billion m³) At Year-end 2005	Natural Gas Reserves		
	Initial Reserves	**Cumulative Production**	**Remaining Established Reserves**
British Columbia	854.9	492.1	362.8
Alberta	4 672.4	3 552.4	1 119.9
Saskatchewan	248.7	167.1	81.6
Subtotal - WCSB	**5 776.0**	**4 211.6**	**1 564.3**
Ontario	46.8	33.8	13.0
Nova Scotia Offshore	55.0	26.5	28.5
Mainland NWT & Yukon	29.3	15.8	13.4
Mackenzie Delta	0.3	0.1	0.2
Subtotal - Frontier	**84.6**	**42.4**	**42.1**
Total Canada	**5 907.4**	**4 287.8**	**1 619.4**

Source: Nova Scotia and Newfoundland Offshore Petroleum Boards for estimates of reserves for the East Coast offshore; NEB for estimates of reserves in the Mainland Territories and Mackenzie Delta; Alberta EUB Alberta's Energy Reserves 2005 and Supply/Demand Outlook 2006-2015; Saskatchewan Reservoir Annual 2003 (Updated by NEB from CAPP data); British Columbia Hydrocarbon and ByProducts Reserves (British Columbia Ministry of Energy and Mines); CAPP Statistical Handbook for Ontario

FIGURE 5.2

Canadian Total Gas Consumption and Heating Degree Days



(a) Estimates

Source: Statistics Canada, NEB and Canadian Gas Association

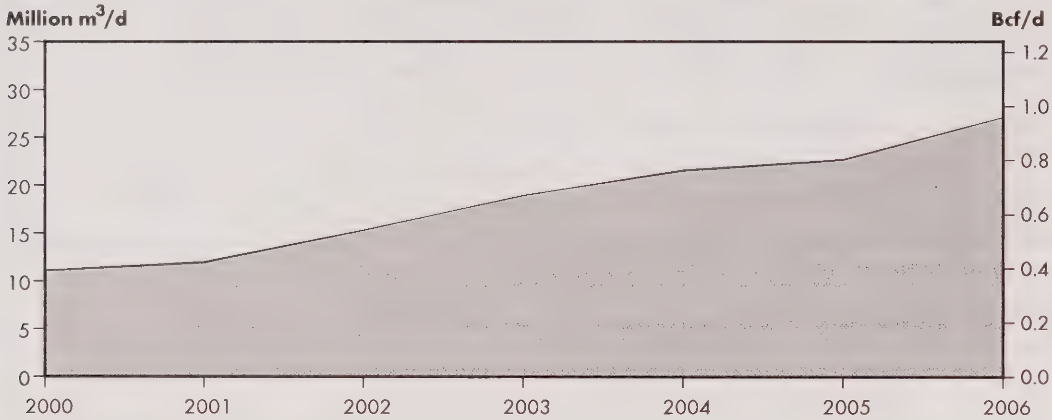
floorspace, actual natural gas consumption has decreased slightly since 2000. Under more "normal" winter weather conditions, such as in 2002-2003, natural gas use could have been higher. In addition to weather effects, higher and more volatile natural gas prices have moderated natural gas consumption, particularly in the price-sensitive industrial sectors.

In contrast to these declines in natural gas consumption, one fast-growing sector for natural gas consumption is the Alberta oil sands. Figure 5.3 shows the natural gas consumption for oil sands operations from 2000 to 2006. In 2005, operational problems at the three major integrated mining/upgrading plants resulted in a reduction in natural gas consumption. Operations returned to normal in 2006 and consumption was approximately 27.1 million m^3/d (0.96 Bcf/d): almost three times the amount of gas used in 2000.

Figure 5.4 shows that natural gas prices have been extremely volatile in recent years. Since 2001, a lack of spare productive capacity in North America has resulted in tight market conditions that have

FIGURE 5.3

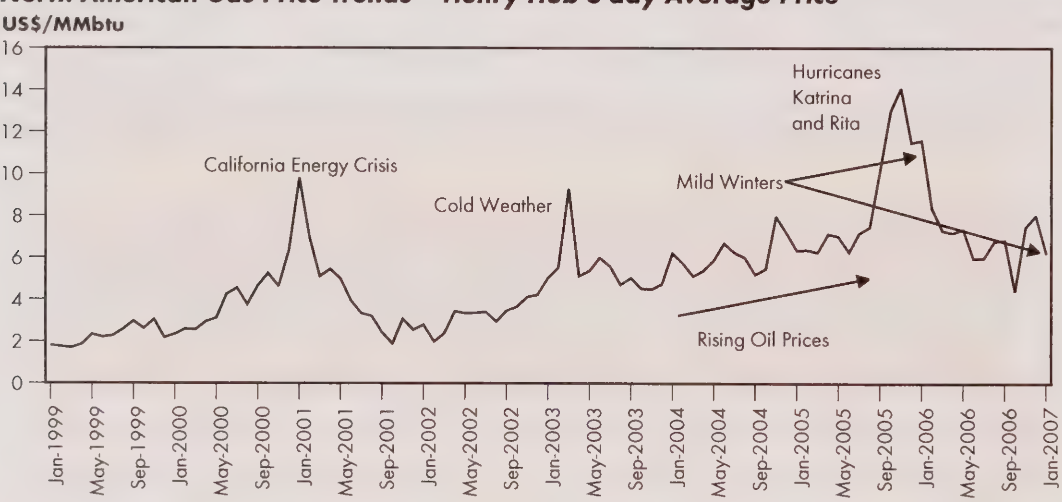
Average Annual Natural Gas Consumption for Oil Sands Operations



Source: NEB and EUB

FIGURE 5.4

North American Gas Price Trends – Henry Hub 3-day Average Price



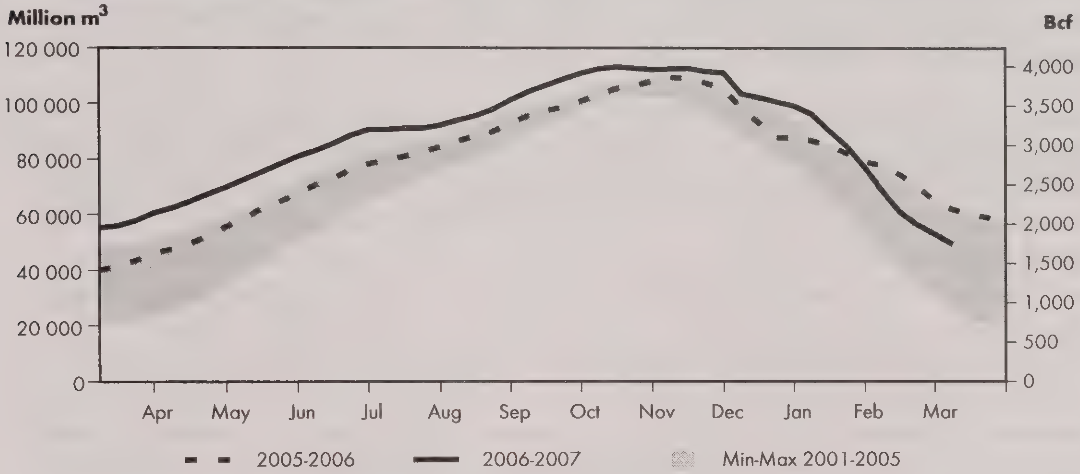
Source: GLJ Energy Publications Inc.

contributed to high and volatile natural gas prices. The price of natural gas is particularly sensitive to weather events and this can result in large swings. In general, some consumers can switch between natural gas and fuel oil, particularly in the U.S. Northeast and Southeast. This competition provides the link between oil prices and natural gas prices, such that an increase in crude oil prices will generally support an increase in the price of natural gas.

Above normal temperatures in the winter of 2005-2006 left record volumes of natural gas in North American gas storage facilities at the beginning of April. April is the beginning of the typical storage injection season (Figure 5.5). Prices remained relatively weak all year as injections into storage continued. Canadian natural gas prices, measured at the AECO hub in Alberta, began 2006 at $8.89/GJ and reached a low of $3.44/GJ in late September before closing the year at $5.74/GJ (Figure 5.6). There was some strengthening of prices in July and August as a heat wave across most of the large North American population centres resulted in increased electric power demand for air conditioning. The summer heat wave's strong call on natural gas prompted an unprecedented

FIGURE 5.5

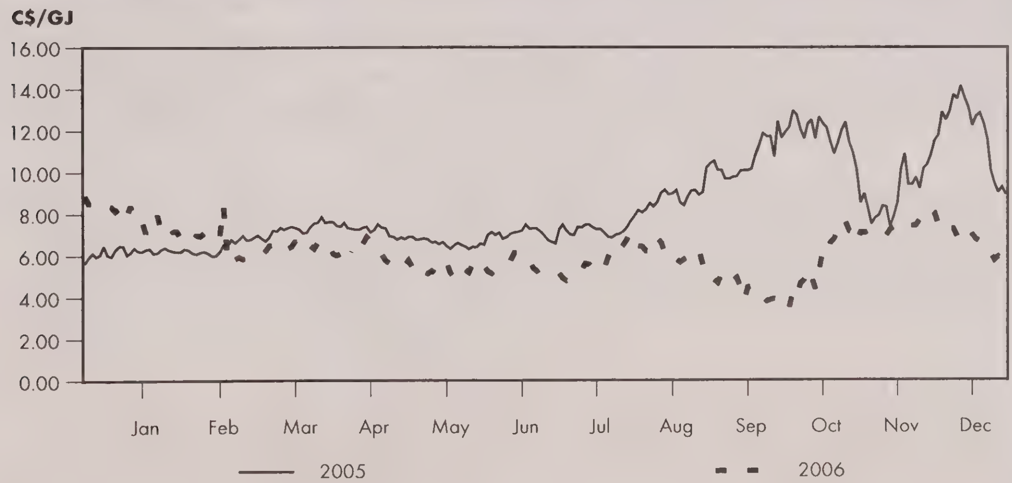
North American Gas Storage Levels



Source: Canadian Enerdata Ltd., NEB estimates, U.S. Energy Information Administration

FIGURE 5.6

Daily AECO Price



Source: Platts

summer withdrawal from storage in the U.S. Storage facilities in Canada continued to fill, albeit at a slower than normal pace, during that period; subsequently, storage levels in Canada stayed within the five year average. Despite the summer withdrawal in the U.S., natural gas storage in North America, particularly in the U.S., reached new record high levels before entering the 2006-2007 winter heating season in November.

Prices in eastern Canadian markets are cited at the Dawn hub, which is located near underground storage facilities in southwestern Ontario, and include a component of transportation and storage costs and are reported in US$/MMBtu (see Figure 5.7). The price of natural gas at Dawn followed a similar path through 2006. The Dawn price began the year at US$9.58/MMBtu and reached a low of US$3.82/MMBtu in late September. The Dawn price recovered closing the year at US$5.74/MMBtu.

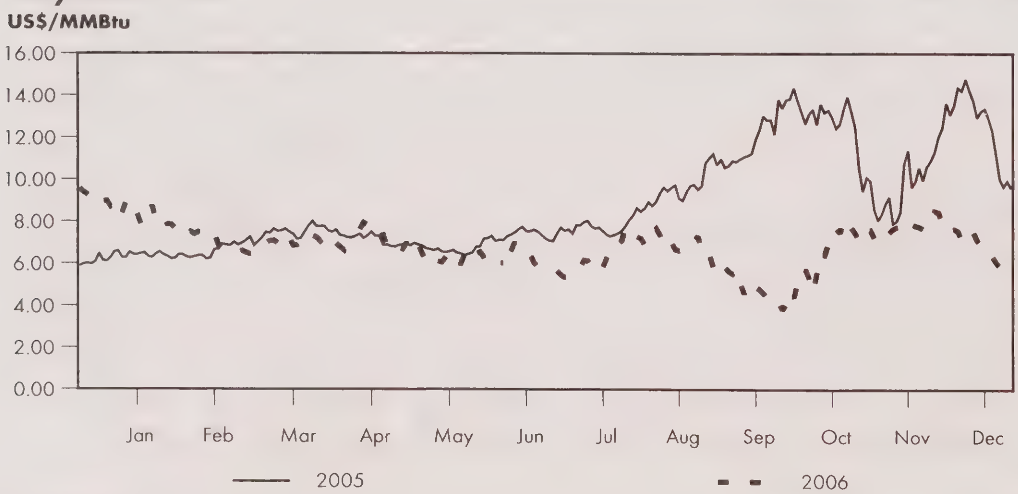
5.5 Canadian Natural Gas Exports and Imports

Natural gas exports for 2006 were estimated to be about 275 million m^3/d (9.6 Bcf/d), or about 16 percent of estimated U.S. consumption. The U.S. Central/Midwest and Northeast regions are Canada's largest export markets. Natural gas is also exported to California and the Pacific Northwest. Canada is a net exporter of natural gas; however, an estimated 26.4 million m^3/d (0.9 Bcf/d) of gas was imported into Ontario from the U.S. in 2006.

Overall, exports of natural gas to the U.S. were lower in 2006 than 2005 (Figure 5.8). The gross volume of Canadian gas exported to the U.S. was down 4.8 percent in 2006 compared with the previous year. Net exports (gross exports less imports) for 2006 were 249 million m^3/d (8.7 Bcf/d), about 4.2 percent lower than the 2005 net export volume of 260 million m^3/d (9.1 Bcf/d). The turbulent weather conditions of 2005 were a contributing factor to this shift with U.S. production losses in the Gulf of Mexico due to Hurricanes Katrina and Rita. In response to the U.S. production losses, Canadian gas exports to the U.S. increased. Consistently above-normal temperatures in the U.S. (particularly in the northern Plains, Great Lakes region and parts of the Northeast and California) in the first quarter of 2006 resulted in lower natural gas demand, and consequently, lower U.S. imports of Canadian gas. Extremely warm temperatures developed in the summer months across major population centres in the U.S. resulting in an increase in gas exports to meet air-conditioning requirements.

FIGURE 5.7

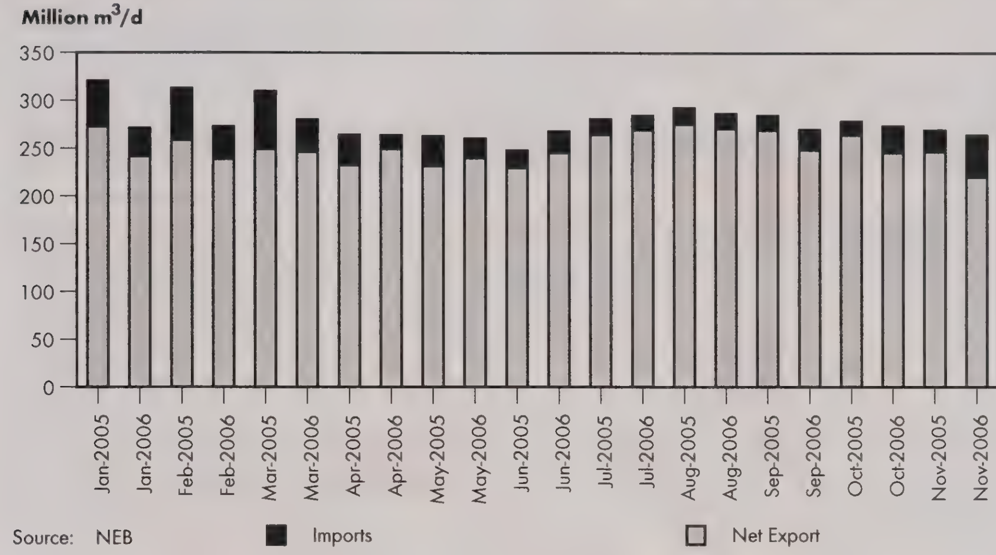
Daily Dawn Price



Source: Platts

FIGURE 5.8

Monthly Export and Import Volumes



Source: NEB

Overall, Canadian revenues from gas exports also saw a year-over-year decrease due to the combination of comparatively lower export volumes and prices of 2006. The average export price was down 19 percent over the previous year, which resulted in net export revenues of \$24.4 billion, about 24 percent below 2005 net export revenues of \$32.1 billion.

5.6 Natural Gas Liquids (excluding Pentanes Plus)

Natural gas liquids (NGLs) refer to the liquid hydrocarbon products extracted from the natural gas stream and are initially recovered as a hydrocarbon mix. The component parts can then be further separated into marketable products such as ethane, propane and butanes. Propane and butanes are also produced from crude oil refining and upgrading processes - products from these processes are also referred to as liquefied petroleum gases (LPG). It is estimated that in 2006, 87 percent of propane and 69 percent of butane supplies came from natural gas production.

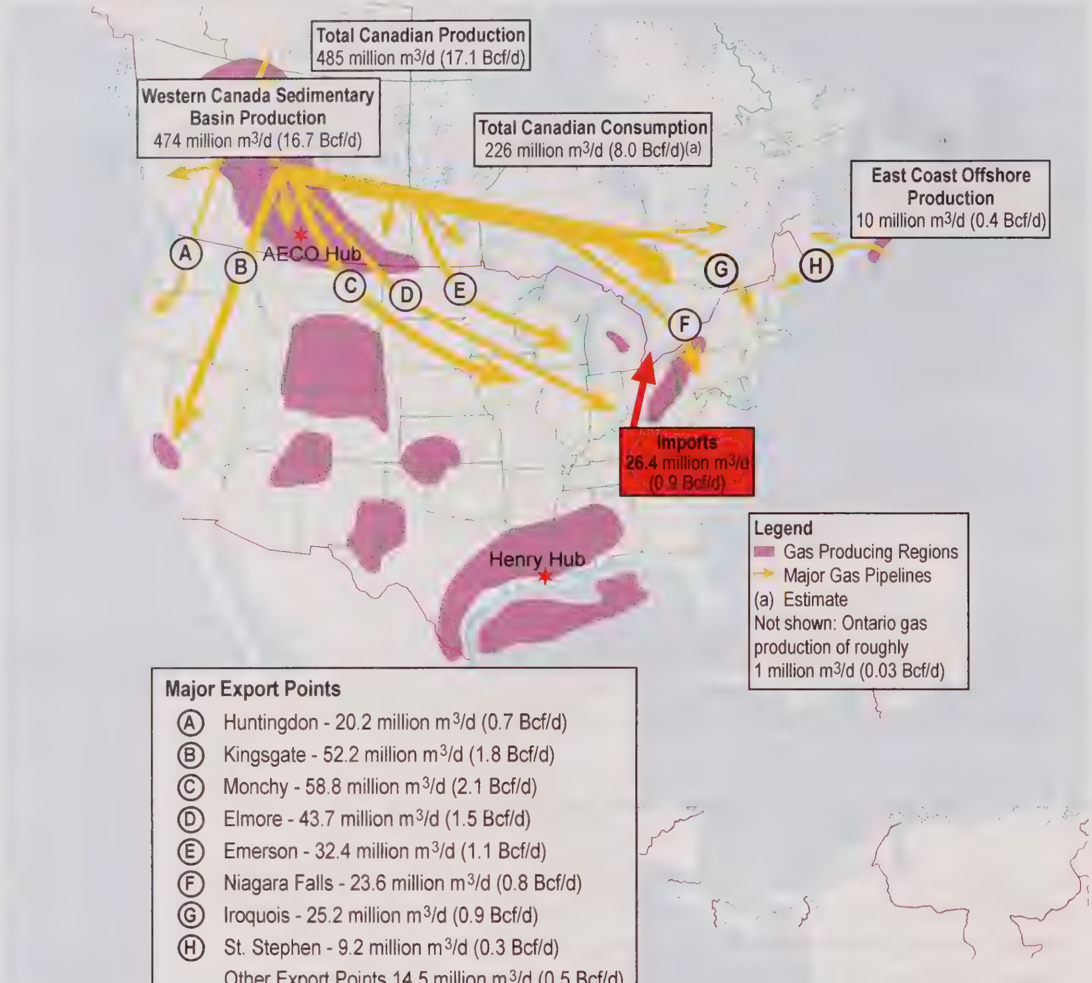
High propane prices, supported by high crude oil prices in the first half of the year and low natural gas prices in the second half of the year, created a favourable environment for propane extraction during 2006. Propane production increased by about three percent to 28 800 m^3/d (181 Mb/d). Strong feedstock demand in the petrochemical sector for propane also helped keep prices high in North America. Ethane and butane production from gas plants remained relatively unchanged at 40 500 m^3/d (255 Mb/d) and 16 900 m^3/d (106 Mb/d), respectively.

In 2006, refinery production for both propane and butane declined from 2005 levels due to lower conventional crude oil production and maintenance at oil sands mining operations. Refinery production of propane is estimated at 3 500 m^3/d (22 Mb/d), an 11 percent decrease since 2005. Butane refinery production declined marginally by one percent because of strong Canadian domestic demand for butane as a heavy oil diluent.

The U.S. Midwest continues to be Canada's largest market for propane and butanes, accounting for about 60 percent of the total export volume. Estimated 2006 propane exports declined by 12 percent to 18 000 m^3/d (113 Mb/d) and butane exports decreased by nine percent to 4 500 m^3/d (28 Mb/d).

FIGURE 5.9

Natural Gas Supply and Disposition – 2006 (Million Cubic Metres per Day)



Source: NEB

The decrease in propane exports was mainly due to lower heating demand caused by mild weather during most of the winter season in North America; whereas, the lower butane export volume was caused by strong diluent demand in the Alberta heavy oil sector.

The higher prices for propane almost offset lower propane export volumes, resulting in estimated 2006 export revenue of $2.1 billion, three percent lower than in 2005. Higher butane prices resulted in 2006 export revenue for butane totalling $622 million, one percent lower than in 2005. Export revenue for the two commodities combined totalled almost $2.7 billion.

5.7 Looking Ahead

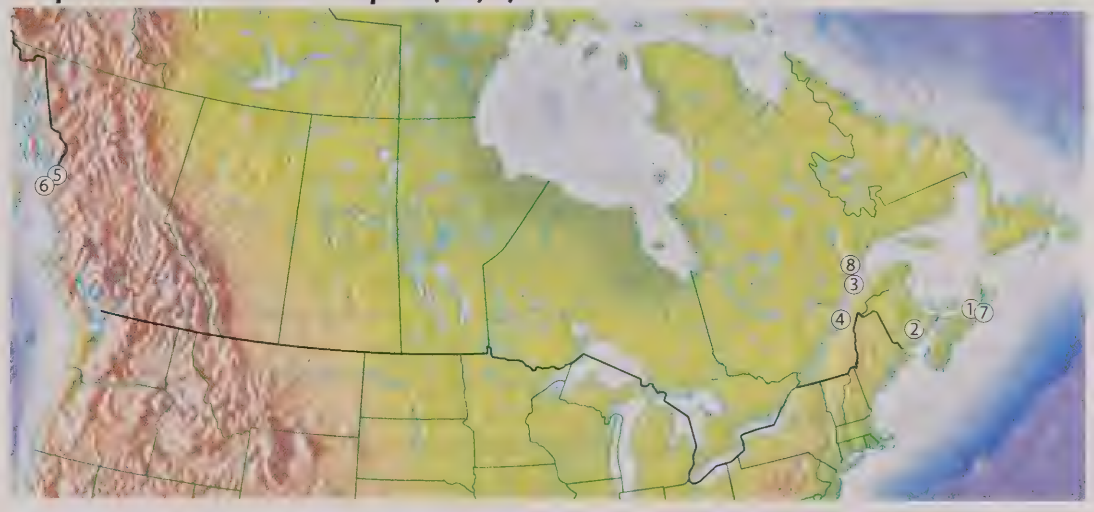
To meet growing natural gas demand, a number of LNG re-gasification facilities have been proposed for sites in Canada. Figure 5.10 outlines these proposed facilities and their capacities and proposed start-up dates.

Changing natural gas market dynamics in Canada are being driven by rising natural gas use by Alberta's oil sands and increasing demand for natural-gas-fired power generation, especially in Ontario. Currently natural gas for power generation in Ontario accounts for about ten percent of

Ontario's total gas consumption; however, the potential for an increase in natural gas consumption is high, primarily driven by the provincial government's decision on power generation in response to air quality concerns. In the past year, 650 MW of new gas-fired power generation was installed in the province.

FIGURE 5.10

Proposed Canadian LNG Projects (Bcf/d)



Location	Terminal	Company	Capacity	Proposed on Stream Date
1. Goldboro, Nova Scotia	Keltic LNG	Keltic Petrochemicals Inc. and Maple LNG	1.0	2009
2. Saint John, New Brunswick	Canaport LNG	Repsol YPF and Irving Oil	1.0	2008
3. Rivière-du-Loup, Quebec	Gros Cacouna LNG	Petro-Canada and TransCanada Pipelines Ltd.	0.5	2009
4. Québec City, Quebec	Rabaska	Gaz Métro, Enbridge and Gaz de France	0.5	2009
5. Ridley Island, British Columbia	WestPac LNG	WestPac Terminals Inc.	0.3	2009
6. Emsley Cove, British Columbia	Kitimat LNG	Gavelston Energy	0.6	2009
7. Point Tupper, Nova Scotia	Statia LNG	Statia Terminals Canada Partnership	0.5	n/a
8. Saguenay, Quebec	Énergie Grande-Anse	Saguenay Port Authority and Énergie Grande-Anse Inc.	1.0	n/a

ELECTRICITY

6.1 Market Development Initiatives

Regional jurisdictions across Canada continued to introduce initiatives aimed at ensuring that adequate supply will be available to meet short-term and long-term demand requirements. The focus on conventional generation sources (e.g., fossil-fuelled generation, nuclear power and hydro electricity) has continued, yet more attention is being put on emerging generation technologies (e.g., wind, biomass and small hydro), investment in transmission infrastructure and demand-side management.

Jurisdictions that experienced periods of tight supply due to high demand responded by increasing generation capacity and transmission capability and introducing market enhancements. For instance, Ontario implemented a number of initiatives to address short-term supply adequacy following reliability challenges experienced during the summer of 2005. In 2006, the province introduced a Standard Offer Program designed to promote small, renewable energy generating projects by making it easier and more cost effective for businesses and entrepreneurs to sell renewable power to the grid by setting a fixed price for the projects. The program is expected to add up to 1,000 MW over the next 10 years.

Much long-term planning is occurring as well. For example, in an effort to meet its longer-term needs, Yukon Energy Corporation filed a 20-year resource plan with the Yukon Utilities Board that addresses resource needs from 2006 to 2025. Proposals include three generation projects and one new transmission line to be in place by 2012.

Jurisdictions are also increasingly using demand-side management initiatives as they develop their resource plans. One example is Ontario's Emergency Load Reduction Program that was introduced in 2006. The program enables major electricity consumers to reduce electricity consumption or to use backup generation on demand by the province's Independent Electric System Operator (IESO). The IESO will pay organizations up to $600 per MW.h for reducing consumption. The program is designed for use in emergency conditions when other options for maintaining reliability are limited.

Resource plans in other regions used programs that focus on both demand-side (conservation and improved energy efficiency) management initiatives and supply-side (generation) increases. For example, the Government of Quebec released its *Energy Strategy 2006 - 2010* in June of 2006. The policy consists of three main objectives: improving energy efficiency and energy savings to 4.7 TW.h in 2010 and to 8.0 TW.h by 2015; a complementary development of hydro and wind power equating to $25 billion in investment that includes 4,500 MW in new hydro projects, and the development of 4,000 MW of wind generation by 2015; and finally, technological innovation. A major objective of the strategy is to increase exports to Ontario and the U.S.

Ontario introduced its Integrated Power System Plan (IPSP), a comprehensive public engagement process coordinated by the Ontario Power Authority. The IPSP will develop the measures necessary to accommodate phasing out coal–fired generation (a recent assessment by the Ontario Power Authority suggests retirement of all coal-fired plants by 2015) and meet Ontario's power needs over the next 20 years. A combination of supply-side and demand-side measures will be used. Renewable generation supply and other diverse generation resources are expected to play a significant role in these plans.

Furthermore, jurisdictions demonstrated that addressing the reliability of supply can be a joint initiative. For instance, a cooperation accord was signed on 2 May 2006 by the energy ministers of Canada's four western provinces and three Arctic territories to help develop and secure energy supplies for the future. Under the accord, each jurisdiction indicated they would harmonize their separate regulatory regimes and better co-ordinate the evaluation and approval of energy development projects.

Electricity prices increased in a number of Canadian jurisdictions in 2006. Increases in demand and higher fuel costs led to a number of provinces and utilities receiving approvals for rate increases from their regulators.

6.2 Electric Reliability Organization (ERO)

There are two main aspects to reliability: adequacy of supply achieved through sufficient generation and transmission capacity; and operating reliability, achieved through operating and maintaining the bulk power system elements so as to withstand disturbances or contingencies and continue operations. In Canada, the reliability of the bulk transmission systems continues to be a focus of the electric industry, regulators and policy makers.

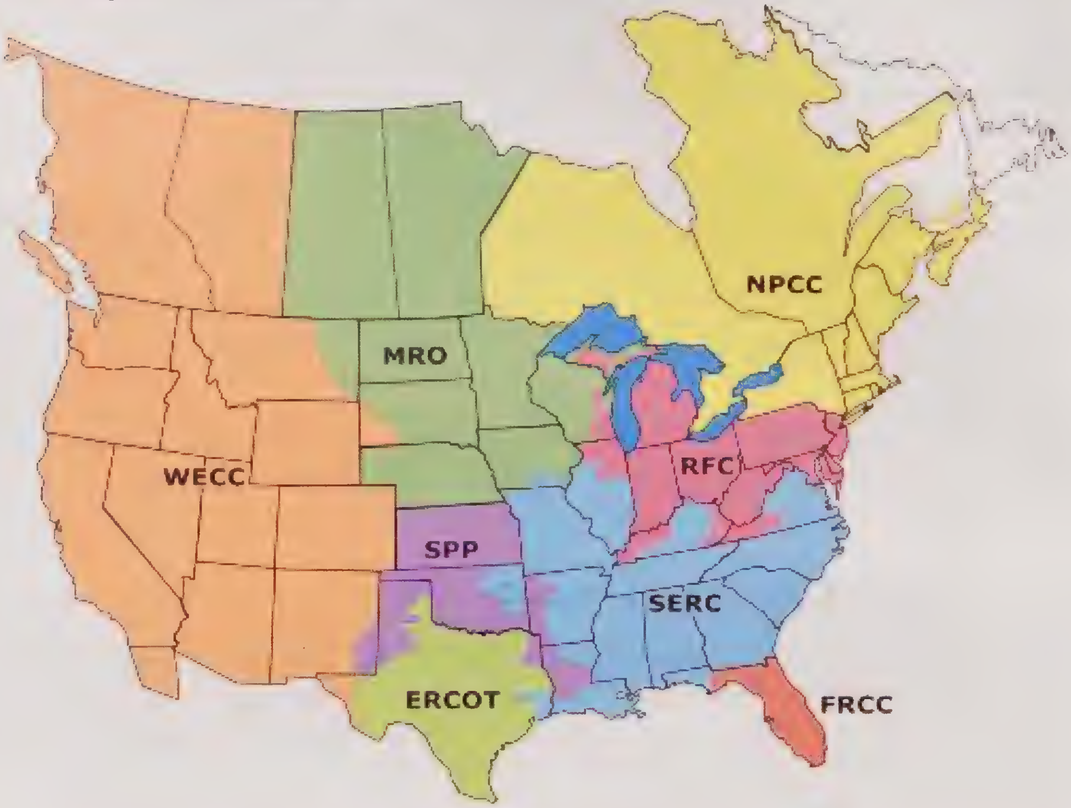
On 20 July 2006, the Federal Energy Regulatory Commission (FERC) certified the North American Electric Reliability Corporation (NERC) as the newly formed Electric Reliability Organization (ERO). In its role as the ERO, NERC has the legal authority to enforce reliability standards on the owners, operators and users of the bulk power system, rather than relying on the system of voluntary compliance overseen by NERC's predecessor, the North American Electric Reliability Council. The creation of the ERO is authorized in the U.S. under the Energy Policy Act of 2005 and was supported by the recommendations made by the Power Outage Task Force following the 23 August 2003 blackout. The ERO commenced operations in January 2007.

On 14 September 2006 the NEB signed a Memorandum of Understanding recognizing NERC as the ERO. The memorandum promotes reliability standards for international power lines under the NEB's jurisdiction in Canada. A number of provinces either enacted legislation or introduced legislation to effectively recognize the NERC as the ERO.

Infrastructure enhancement initiatives took place on a variety of levels in 2006. Some projects were targeted to address more localized issues through upgrades. For example, on 7 July 2006, the British Columbia Transmission Corp. received approval from the British Columbia Utilities Commission to build two new underwater 230 kV lines between the British Columbia mainland and Vancouver Island. This project follows the June 2005 cancellation of the Duke Point Power Project, a gas-fired generation project on the island, because of the risk the plant would not be built on time. The $250 million project will replace the two deteriorating 138 kV cables from the mainland. The new lines are expected to be completed by October 2008. An environmental assessment review process was still being conducted at the end of 2006.

FIGURE 6.1

NERC Regions and Subregions



- Mandatory reliability standards are administered by NERC's regional reliability organizations including the Northeast Power Coordinating Council (NPCC) (Ontario, Québec and the Maritimes), the Midwest Reliability Organization (MRO) (Saskatchewan and Manitoba) and the Western Electricity Coordinating Council (WECC) (British Columbia and Alberta).
- Provincial government agencies and the NEB have regulatory oversight in their respective jurisdictions in Canada.
- The FERC has regulatory oversight over the NERC in the U.S.

Other projects addressed local needs through the expansion and addition of new transmission lines. The EUB approved ATCO Electric's application to reinforce the northwestern transmission system. The $300 million in planned transmission upgrades northwest of Edmonton includes one 138 kV line and one 240 kV line by 2009 and one 240 kV line by 2014.

Quebec also made intra-provincial investments in transmission infrastructure in 2006. Projects included a variety of infrastructure additions including two 69 kV lines, one 315 kV line, and new and upgraded substations.

Provinces and utilities worked together to accomplish supply reliability initiatives. Ontario and Quebec reached an agreement on 14 November 2006 to develop an inter-provincial transmission line linking their grids to reduce the need to import from the U.S when demand exceeds capacity. When constructed, the line could add up to 1,250 MW of power to Ontario from Quebec, therefore increasing the stability of Ontario electricity supply. The line is expected to be operational in 2010.

International reliability initiatives moved forward on several fronts. On 15 September 2006, the NEB approved the first merchant international transmission line. Sea Breeze Converter Corporation was approved to build a 150 kV power line from Vancouver Island to Port Angeles, Washington.

New Brunswick also began the construction of its 345 kV international transmission line in November 2006. The Board approved the line following the EH-2-2002 proceeding. The line will connect the transmission systems of Maine and the three Maritime provinces and will extend from Point Lepreau, New Brunswick to the U.S. border at Woodland, Maine. The expected in-service date is December 2007.

In an effort to address potential operational reliability concerns and avoid putting additional stress on its transmission system, the Alberta Electric System Operator (AESO) announced in May that there would be a 900 MW upper limit for wind generation in the province. The main reason cited for this decision was the potential reliability problems associated with managing wind generation on the Alberta integrated energy system. At the end of 2006, Alberta had 384 MW of wind generation capacity.

6.3 Electricity Generation

At the end of 2006, Canada's total installed generation was 122,898 MW, an increase of 54 MW from 2005. Total Canadian electricity generation declined slightly from 597 TW.h in 2005 to 589 TW.h in 2006 (Table 6.1). Hydro electric generation declined from 358 TW.h in 2005 to 353 TW.h in 2006. The decrease occurred despite the adequate water season for hydro generating provinces. Thermal generation declined slightly from 152 TW.h in 2005 to 141 TW.h in 2006. This change can be attributed, in part, to the milder weather experienced across the country throughout the year. Additional generation support came from the restart of Ontario Power Generation's Pickering A, Unit 1 of approximately 500 MW in November 2005 which helped to increase nuclear generation from 87 TW.h in 2005 to 94 TW.h in 2006. Hydro electric, thermal and nuclear generation accounted for 60, 24 and 16 percent of total Canadian generation, respectively.

A strategy for increasing capacity continued to include diversification of generation, which was largely achieved through the requirement for generation projects that use emerging technologies. This strategy was partially supported by rising long-term fuel costs for thermal generators. An advantage of capacity additions from emerging technologies (such as wind power) is the often shorter construction lead time.

Following the second phase of a request for proposals issued in May 2005 for 45 MW of capacity under its Environmentally Preferred Power (EPP) program, SaskPower selected a wind farm (25 MW) and three heat-recovery units at natural gas pipeline compressor station sites (5.1 MW each). The EPP program is designed to meet new load growth to 2010 with smaller generation projects that produce no new greenhouse gases and contribute to environmental sustainability.

British Columbia's December 2005 call for power to purchase 285 MW by 2010 resulted in a response that had a high concentration of renewable projects. In an attempt to become less reliant on imports, BC Hydro awarded, and the British Columbia Utilities Commission approved, 38 projects that will supply 1,439 MW to the grid. The projects include 29 hydro electric, three wind, two biomass, two waste-heat and two coal/biomass generators. All projects are to be online by 2010.

Wind generation projects grew across the country becoming an increasingly larger component of generation portfolios in many provinces. Capacity more than doubled in 2006, to 1,460 MW year end from just over 680 MW in 2005. Ontario had the biggest increase in 2006 with nearly 400 MW

TABLE 6.1

Electricity Production[a]
(Terawatt Hours)

	2002	2003	2004	2005	2006[b]
Hydroelectric	345.9	332.9	335.1	358.4	353.1
Nuclear	71.3	70.7	85.3	86.8	94.3
Thermal	161.6	160.7	150.9	151.8	141.1
Total	**578.8**	**564.3**	**571.3**	**597.0**	**588.5**

(a) Source: Statistics Canada Energy Statistics Handbook. Table 8.2 Utility Generation of Electricity in Canada and Table 8.3 Industry Generation of Electricity in Canada

(b) Estimates

of wind projects, bringing the province's total to 413 MW at the end of the year. Several provinces continue to move forward with new planned projects. According to the Canadian Wind Energy Association, by the end of 2006, Canada ranked twelfth in the world in terms of wind energy capacity.

New natural-gas-fired generation continued to experience strong growth. For example, the Ontario Power Authority awarded a contract to TransCanada Corporation to build a 683 MW gas-fired generation facility. This is in addition to the 550 MW Portlands Energy Centre and the 880 MW Goreway Station, which were awarded contracts earlier in the year.

In 2006, there was a continued resurgence in large hydro generation projects. An agreement was signed on 14 June 2006 between Manitoba Hydro and the Nisichawayasihk Cree Nation to develop the 200 MW Wuskwatim hydro generation station. The $1.2 billion project is estimated to be completed in 2012. Manitoba Hydro also moved forward with its proposal to construct the Conawapa generating station, a 1,250 MW development in northern Manitoba. If constructed, the $5 billion generating station will be the province's largest. Additionally, Quebec's Eastmain 1-A 890 MW hydro project received provincial and federal approval in November and December, respectively.

In Labrador, the government announced that it would take the lead in developing the proposed Lower Churchill River hydro electric project. If it goes ahead, the project would be built and operated by Newfoundland & Labrador Hydro. The earliest date the project would start generating electricity would be 2015. A final decision on whether to proceed with the project is expected to be made in 2009.

6.4 Electricity Demand

During 2006, electricity demand was adequately met across the country as temperatures remained mild, particularly during the winter heating season. However, through the summer, some transmission systems were challenged.

Ontario is the only province where the peak electricity load is in the summer. The IESO experienced two extremes that taxed its system on 1 August 2006. First the province experienced a record high demand (approximately 27,000 MW versus a capacity of approximately 31,000 MW) and then on 3 September 2006 it experienced a record low (off-peak) demand (approximately 12,000 MW). The low demand resulted in a negative price of -$3.10 per MW.h. This negative price occurred because suppliers were willing to pay to run their generating units in order to meet their minimum generation output requirements.

Although a region's physical system may be balanced from an overall supply and demand perspective, short-term, tight balance conditions can still occur. Such was the case in Alberta on 24 July 2006 when the following events occurred within the same critical timeframe stressing the province's generation: three coal units were offline for scheduled maintenance; two units tripped offline; hot weather increased electricity demand; and lightning reduced the use of the Alberta/British Columbia intertie. The result was rotating blackouts. The situation was mitigated by co-ordination with other regions and voluntary demand reductions within the province.

6.5 Electricity Exports and Imports

Compared to 2005, which was a favourable water year for hydro electricity generation, net exports decreased 26 percent in 2006 to 17.4 TW.h due to an increase in imports. Net exports were up four percent from the five-year average of 16.7 TW.h.

Exports declined four percent to 41.2 TW.h and were 14 percent above the five-year average of 36.1 TW.h. Imports increased by 23 percent in 2006 to 23.8 TW.h. Additionally, export revenues declined 21 percent from $3.15 billion in 2005 to $2.50 billion in 2006. Canada imported $1.18 billion of electricity in 2006 compared with $1.27 billion in 2005, a decline of eight percent. The impact on exports can be attributed to the milder weather in export regions throughout 2006, while lower cost power helped support the increase in imports.

Hydro electric generation is the largest single source of generation in Canada. Therefore, a strong export year largely depends on the major hydro generating provinces of British Columbia, Manitoba, Ontario and Quebec. These provinces were the largest exporters of electricity in 2006 consisting of 13 percent, 30 percent, 22 percent and 28 percent of total Canadian exports, respectively. Hydro generating provinces actively trade to take advantage of off-peak and on-peak prices south of the border, importing electricity in order to store water behind their reservoirs for future generation opportunities. The largest importers of electricity were British Columbia, Ontario and Quebec accounting for 51 percent, 27 percent and 11 percent of total Canadian imports, respectively.

FIGURE 6.2

International and Interprovincial Transfers of Electricity[a] (Gigawatt Hours)

6.6 Looking Ahead

Looking forward, jurisdictions will continue to implement measures to ensure an adequate supply of electricity. Emerging technologies are expected to make up a larger percentage of generation portfolios, although this is still quite small relatively speaking. Wind is expected to lead the way in this growth. Increases in demand-side management will result as initiatives gain momentum to curb demand growth. Governments, system planners and electric utilities are likely to support greater implementation of these technologies. Investment in transmission infrastructure will be required to meet electricity supply and operating reliability requirements. Additionally, jurisdictions will continue initiatives to cooperate with each other for supply and operating reliability purposes.

Electricity rates will increase over the longer term as fuel prices and operating costs rise and new infrastructure is added. Short-term price fluctuations will be influenced by weather and the occurrence of temporary tight supply situations.

Electricity industry participants will continue to look for export opportunities to the U.S. A favourable export year will depend on water conditions in the hydro generation provinces and demand for cooling and heating in the summer and winter months, respectively.

Conclusion

The importance of the energy sector to the Canadian economy continues to grow, accounting for 5.9 percent of total GDP and C$99 billion of export revenues in 2006. Export revenues grew by 19 percent compared with 2005 and accounted for 22 percent of the value of all exports. While export volumes continue to climb and export revenue grows, the trend in Canada appears to be increasing awareness of energy efficiency and consumption patterns.

Canadians are beginning the journey to more efficient use of energy. In 2006, energy consumption increased by only 1.1 percent, compared with the five-year annual average of two percent. During the 2002 to 2006 period, Canadian total energy demand on average increased by 1.8 percent per year, compared with the rising average real GDP rate of 2.8 percent per year. Energy intensity has therefore improved during this time. This improvement is largely in transportation demand, suggesting that Canadians are responding to higher fuel prices by altering their driving behaviour. However, other factors such as government initiatives, growing awareness about conservation, and warmer winter temperatures are also likely key contributors.

The increasing importance of oil production to Canada's economy is indicated by the oil export revenues which increased to C$39.3 billion dollars, surpassing export revenues generated from natural gas exports for the first time in many years. Investment in the oil sands is contributing to strong economic growth in Alberta and spin-off opportunities in other provinces. Looking forward, oil sands expansion is expected to continue at an aggressive pace, which will have a continuing positive effect on crude oil export revenues, but will also require extension of markets and pipeline capacity in Canada and the U.S.

Weather has a tremendous impact on prices and consumption for natural gas in North America, and warmer winter temperatures resulted in reduced gas export volumes and revenues in 2006.

The generally lower natural gas prices that have been experienced over the last 18 months have been a major factor in the overall reduction in gas-directed drilling effort that began around mid-2006. To date, the overall impact of the lower drilling levels on gas production has been slight, but, going forward, lower gas drilling levels can be expected to exert further downward pressure on WCSB gas production volumes.

Overall, Canadian consumption of natural gas is expected to rise over the foreseeable future, in part related to growing oil sands demand in Alberta and replacement of coal-fired generation in Ontario. This increase would be taking place in an environment of flat or declining domestic natural gas production. Against this backdrop, projects are being proposed to bring LNG into Canada to support domestic consumption and exports to the U.S. market

In 2006, various jurisdictions of the Canadian electricity industry introduced a number of initiatives to ensure adequacy of supply. Looking to the future, adequacy of supply and operating reliability will continue to be in the forefront. Mainstay generation sources such as fossil-fuelled generation, nuclear power and hydro-electricity will see more support from emerging technologies (i.e., wind, biomass and small hydro), and investment in transmission infrastructure and demand-side management.

Glossary

Bitumen or crude bitumen	A highly viscous mixture, mainly hydrocarbons heavier than pentanes. In its natural state it is not usually recoverable at a commercial rate through a well because it is too thick to flow.
Coalbed methane	A form of natural gas extracted from coalbeds. Coalbed methane, often referred to as CBM, is distinct from a typical sandstone or other conventional gas reservoir as the methane is stored within the coal by a process called adsorption.
Coiled tubing drilling rig	A specialized drilling rig that uses a long, continuous length of pipe with a downhole mud motor to turn the bit while drilling a well. The continuous pipe arrives coiled on a spool and is straightened as it enters the well and rewound on the spool as it is withdrawn. This differs from a traditional drilling rig that uses jointed pipe with the bit often propelled from the rig floor or top of the drill pipe. Coiled tubing drilling operations proceed quickly compared to using a jointed pipe drilling rig because pipe connection time is eliminated when withdrawing and reinserting the drill pipe in the well during drilling operations. Being smaller, a coiled tubing drilling rig requires less surface area to operate and is more readily moved between locations.
Conventional crude oil	Crude oil, which at a particular point in time, can be technically and economically produced through a well using normal production practices and without altering the natural viscous state of the oil.
Conventional gas	Refers to natural gas from all sources other than CBM.
Deliverability	The amount of natural gas a well, reservoir, storage reservoir or producing system can supply at a given time.
Diluent	Any lighter hydrocarbon, usually pentanes plus, added to heavy crude oil or bitumen to facilitate its transport on crude oil pipelines.
Hub	A geographic location where large numbers of buyers and sellers trade a commodity and where physical receipts and deliveries occur.

In situ recovery	The process of recovering crude bitumen from oil sands other than by surface mining.
Line Pack	The actual amount of gas in a pipeline or distribution system.
Marketable Gas	Natural gas that has been processed to remove impurities and natural gas liquids. It is ready for market use.
Natural Gas Liquids	Those hydrocarbon components recovered from natural gas as liquids. These liquids include, but are not limited to, ethane, propane, butanes and pentanes plus.
Oil sands	Sand and other rock material that contains bitumen. Each particle of oil sand is coated with a layer of water and a thin film of bitumen.
Pentanes Plus	A mixture mainly of pentanes and heavier hydrocarbons obtained from the processing of raw gas, condensate or crude oil.
Reserves – Established	The sum of the proven reserves and half probable reserves.
Reserves – Initial Established	Established reserves prior to deduction of any production.
Reserves – Proven	Reserves recoverable under current technology and present and anticipated economic conditions, specifically demonstrated by drilling, testing or production.
Reserves – Remaining	Initial reserves less cumulative production at a given time.


National Energy Board
Office national de l'énergie

Canadian Energy Overview 2007



AN ENERGY MARKET ASSESSMENT MAY 2008

Canada

National Energy Board   Office national de l'énergie

Canadian Energy Overview 2007

AN ENERGY MARKET ASSESSMENT MAY 2008

Canada

Cat. No. NE2-4/2007E
ISBN 978-0-662-47952-9

This report is published separately in both official languages. This publication is available upon request in multiple formats.

Copies are available on request from:
The Publications Office
National Energy Board
444 Seventh Avenue S.W.
Calgary, Alberta, T2P 0X8
E-mail: publications@neb-one.gc.ca
Fax: 403-292-5576
Phone: 403-299-3562
1-800-899-1265
Internet: www.neb-one.gc.ca

For pick up at the NEB office:
Library
Ground Floor

Printed in Canada

N° de cat. NE2-4/2007F
ISBN 978-0-662-08251-4

Ce rapport est publié séparément dans les deux langues officielles. On peut obtenir cette publication sur supports multiples, sur demande.

Demandes d'exemplaires :
Bureau des publications
Office national de l'énergie
444, Septième Avenue S.-O.
Calgary (Alberta) T2P 0X8
Courriel : publications@neb-one.gc.ca
Télécopieur : 403-292-5576
Téléphone : 403-299-3562
1-800-899-1265
Internet : www.neb-one.gc.ca

Des exemplaires sont également disponibles à la bibliothèque de l'Office :
Rez-de-chaussée

Imprimé au Canada

FIGURES

TABLES

AUC	Alberta Utilities Commission
CBM	coalbed methane
CNSC	Canadian Nuclear Safety Commission
EIA	Energy Information Administration
EMA	Energy Market Assessment
ERCB	Alberta Energy Resources Conservation Board
EUB	Alberta Energy and Utilities Board
FEED	front-end engineering and design
GDP	gross domestic product
IESO	Independent Electric System Operator
IPPI	Industrial Product Price Index
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MOU	Memorandum of Understanding
NEB or Board	National Energy Board
NGLs	natural gas liquids
NRCan	Natural Resources Canada
NYMEX	New York Mercantile Exchange
OPEC	Organization for Petroleum Exporting Countries
PADD	Petroleum Administration for Defence District
PSAC	Petroleum Services Association of Canada
U.S. or US	United States
WCSB	Western Canada Sedimentary Basin
WTI	West Texas Intermediate

LIST OF UNITS

b/d	barrels per day
Bcf/d	billion cubic feet per day
GJ	gigajoule
kV	kilovolt
m^3/d	cubic metres per day
Mb/d	thousand barrels per day
MMb/d	million barrels per day
MMbtu	million British thermal units
MW	megawatt
PJ	petajoules
$ or Cdn$	Canadian dollars
US$	U.S. dollars
TW.h	terawatt hour

FOREWORD

The National Energy Board (NEB or the Board) is an independent federal agency that regulates several aspects of Canada's energy industry. Its purpose is to promote safety and security, environmental protection and efficient energy infrastructure and markets in the Canadian public interest within the mandate set by Parliament in the regulation of pipelines, energy development and trade. The Board's main responsibilities include regulating the construction and operation of interprovincial and international oil and gas pipelines as well as international and designated interprovincial power lines. The Board regulates pipeline tolls and tariffs for pipelines under its jurisdiction. The Board regulates the exports and imports of natural gas as well as exports of oil, natural gas liquids (NGLs) and electricity. The Board also regulates oil and gas exploration, development and production in frontier lands and offshore areas not covered by provincial or federal management agreements. The Board's advisory function requires it to keep under review matters over which Parliament has jurisdiction relating to all aspects of energy supply, transmission and disposal of energy in and outside Canada.

The NEB monitors energy markets to objectively analyze energy commodities and inform Canadians about trends, events and issues. Annually, the Board does a review of the past year's energy markets in this Energy Market Assessment (EMA), entitled *Canadian Energy Overview 2007*. This report is a summary of major developments related to energy in Canada in 2007.

INTRODUCTION

In the past year, the Board issued a number of Energy Market Assessments (EMAs) on a wide range of energy commodities. In addition, it released its *2007 Canada's Energy Future - Reference Case and Scenarios to 2030*. The report is a comprehensive energy supply and demand outlook for the years 2005 to 2030. These reports and related information can be found on the Board's website at http://www.neb-one.gc.ca.

In 2007, global energy markets were impacted by rising and fluctuating prices for crude oil and escalating finding and development costs. The year began with lower prices for crude oil and natural gas, primarily driven by above normal temperatures in North America and high inventory levels for crude oil, including petroleum products, and natural gas. By summer, crude oil prices were on the rise and eventually reached record highs in the fall and winter months. By year end, crude oil prices had risen by 76 percent from the lows witnessed in January. The rise in the price of crude oil was moderated in Canada with the appreciation of the Canadian dollar versus the U.S. dollar.

Energy continued to be an important factor in the Canadian economy. In 2007, the energy industry accounted for 5.6 percent of Canada's gross domestic product (GDP) and 19.7 percent ($90.0 billion) of the total value of Canadian exports. In 2007, the energy industry's capital and repair expenditure totalled $68.9 billion – about 35 percent of total private sector investment. Following a decrease in 2006, total secondary energy demand is estimated to have increased 2.8 percent between 2006 and 2007 to 10 976 PJ. This was supported by robust population growth and economic growth.

Influenced by global events such as strong world oil demand growth, lack of spare production and refining capacity, and political instability in some oil producing regions, crude oil prices averaged US$72 per barrel in 2007, an increase of about 10 percent from 2006. A commonly used international benchmark, West Texas Intermediate (WTI) began the year at about US$54 per barrel and reached a record US$99 per barrel in November, driven by a tight supply and demand balance, strong oil demand growth in the Middle East and Asia and a depreciating U.S. dollar making oil cheaper in oil consuming countries. By year-end, crude oil closed at approximately US$96 per barrel, significantly higher than where it began the year.

In 2007, the value of crude oil exports surpassed the value of natural gas exports. Net crude oil and products export revenue, which is estimated at roughly Cdn$25.7 billion, exceeded the value of net natural gas export revenue of Cdn$24.3 billion. The gap has narrowed from 2003, when the difference was approximately Cdn$8 billion, with natural gas having higher export revenues of the two commodities. Net natural gas export revenues have remained steady at Cdn$24.3 billion in 2006 and 2007, while net crude oil exports have increased to Cdn$25.7 billion in 2007, an increase of 18 percent compared with 2006.

Despite supply interruptions in 2007, average crude oil production was up seven percent compared with 2006, to 441 128 m^3/d (2.8 MMb/d). This increase reflects growing oil sands production, plus increases in production at the Terra Nova and White Rose Fields offshore eastern Canada.

In 2007, natural gas prices were lower and less volatile than they have been in recent years as a result of a well-supplied North American natural gas market. Warmer-than-normal weather during the winter of 2006-07 in North America, record U.S. imports of liquefied natural gas (LNG) during the summer of 2007 and increased natural gas production in several U.S. basins helped to maintain a very high inventory of natural gas in storage. As a result, North American natural gas prices at Henry Hub, the pricing point in Louisiana for natural gas traded on the New York Mercantile Exchange (NYMEX), ranged between US$6/MMBtu and US$8/MMBtu throughout the year. Natural gas is priced in American dollars; therefore, the appreciation of the Canadian dollar resulted in lower prices for Canadian consumers.

The combination of rising costs for natural gas development and lower natural gas prices in 2007 resulted in lower natural gas drilling and investment in Western Canada. Consequently, total natural gas related drilling was down significantly compared with 2006. Total Canadian natural gas production averaged 475 million m^3/d (16.8 Bcf/d), or roughly 2 percent less than in 2006. The decline was concentrated in the Western Canada Sedimentary Basin (WCSB). Total production declines were partially offset by slightly higher production on the East Coast. The East Coast increases were from a new onshore development in New Brunswick and from the effect of added compression offshore Nova Scotia.

Natural gas continued to supply a significant part of Canadian and North American energy requirements. In 2007, estimated Canadian natural gas consumption was about 233 million m^3/d (8.2 Bcf/d), or 46 percent of Canadian production. Although Canadian natural gas consumption in most end-use sectors remained flat or declined, oil sands development continued to be a significant and fast-growing sector for consumption. In 2007, the natural gas consumed for oil sands development was almost 32 million m^3/d (1.1 Bcf/d) - over three times the amount of gas used in 2000. Over one-third of domestic natural gas consumption continued to be directed toward residential and commercial use, primarily for space and water heating. Despite continued growth in floor space (i.e., the number and size of buildings) for these sectors, natural gas consumption remains flat as this growth has been largely offset by warmer weather in recent years.

Canadian natural gas exports were estimated to be 293 million m^3/d (10.4 Bcf/d), slightly higher than in 2006. Net exports (gross exports less imports) were about 260 million m^3/d (9.1 Bcf/d), about 4.4 percent higher than in 2006. Despite the higher export volumes, export revenues remained about the same as 2006 at $24.3 billion, reflecting the overall lower North American natural gas price.

Electricity jurisdictions continued to introduce initiatives in 2007 that were intended to address adequacy of supply and operating reliability. Such initiatives included conservation measures, clean energy programs and infrastructure additions. In order to promote electric reliability, efforts to upgrade and expand transmission infrastructure on international and provincial levels also continued. With respect to electricity supply, although conventional generation (e.g., coal, nuclear, natural gas and hydro generation) still prevails in the electric generation asset mix, alternative forms were included as supply source additions. In 2007, there was also a resurgence of interest in nuclear generation.

Overall, Canada's electricity demand was adequately met in 2007 with generation increasing from 585 terawatt hours in 2006 to 600 terawatt hours in 2007. Net exports increased from 17.4 terawatt hours in 2006 to 30.6 terawatt hours. Canada exported approximately $3.1 billion of electricity and imported a total of $1 billion in 2007 resulting in net revenues of $2.1 billion, compared to approximately $1.3 billion in 2006. Favourable water conditions in hydrogeneration provinces contributed to the strong electricity trade results.

Energy and the Canadian Economy

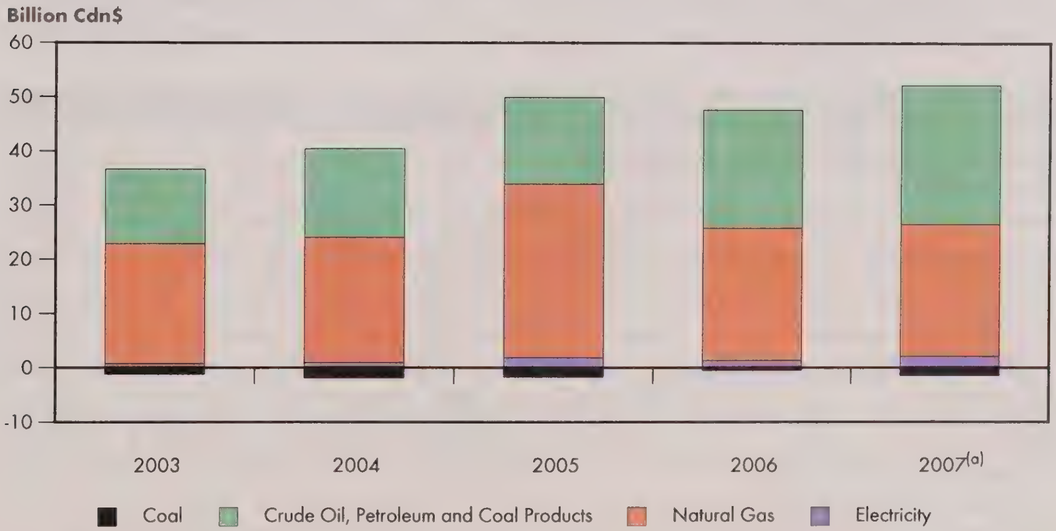
In 2007, the energy industry accounted for 5.6 percent of Canada's GDP and directly employed 372 200 people (2.2 percent of the Canadian labour force). Energy export revenue totalled $90 billion, which accounted for 19.7 percent of the value of all exports. The proportion has held roughly steady for the last three years and is double the 1990's average of 10 percent of export value.

Overall, net energy export revenues (the value of energy exports minus the value of energy imports) increased by almost eight percent from 2006 levels to $50.8 billion in 2007 (Figure 2.1). Historically, net natural gas exports have been larger than crude oil and products net export revenues; however, in 2006 the net export revenue of natural gas and crude oil and products were almost equal and in 2007, the net export revenue of crude oil and products was $2 billion greater than natural gas net export revenues. This is a result of increased export volumes and strong crude oil prices combined with the maturing natural gas basin in Western Canada and softening natural gas prices. Electricity net export revenue experienced growth between 2006 and 2007 as a result of favourable export opportunities south of the Canada/United States border and good water conditions in the hydrogenerating provinces such as, British Columbia, Manitoba and Quebec. Canada continued to be a net importer of coal in 2007.

Total energy production in Canada increased by 1.8 percent in 2007, largely due to increased petroleum production, as well as wind production (Table 2.1). Offsetting total growth in Canadian

FIGURE 2.1

Net Energy Export Revenues, 2003 - 2007



(a) Estimate

Source: Statistics Canada, NEB

TABLE 2.1

Domestic Energy Production by Energy Source (petajoules)

	2003	2004	2005	2006	2007[a]
Petroleum[b]	6 479	6 667	6 545	6 862	7 235
Natural gas[c]	6 462	6 524	6 373	6 585	6 484
Hydroelectricity	1 198	1 206	1 291	1 271	1 302
Nuclear	820	989	1 007	1 072	1 020
Coal	1 326	1 476	1 494	1 554	1 586
Renewable and other[d]	633	657	681	709	733
Total	**16 918**	**17 519**	**17 391**	**18 053**	**18 360**

(a) Estimates

(b) Petroleum includes crude oil and gas plant natural gas liquids (NGLs), upgraded and non-upgraded bitumen and condensate

(c) Marketable natural gas

(d) Includes wind, solar, solid wood waste, spent pulping liquor and annual firewood

Source: Statistics Canada, NEB

production was a decline in natural gas production as a result of a slow down in drilling activity in Western Canada and decreased nuclear energy production due to plant outages during the year. Additional details on Canadian production trends in 2007 are provided in the following chapters.

Preliminary 2006 numbers suggest Canadian energy demand fell from 2005 levels as a result of decreased energy use across most end-use sectors. Initial estimates suggest a resurgence of energy demand growth in 2007. Total secondary energy demand is expected to increase to 10 976 PJ in 2007, which is 2.8 percent above 2006 levels (Table 2.2). Secondary or end-use energy demand is the energy used by the final consumer in Canada and is separated into four sectors: residential, commercial, industrial and transportation.

Canadian energy demand trends are driven by changes in population, economic conditions, energy prices, weather, conservation, technology and consumer preferences. Statistics Canada reports that the Canadian population increased by 1.8 percent in 2007, with net international migration accounting for two thirds of this growth. In comparison, the population increased by one percent

TABLE 2.2

Domestic Secondary Energy Consumption (petajoules)

	2003	2004	2005	2006[a]	2007[a]
Residential[b]	1 448	1 425	1 410	1 369	1 442
Commercial	1 444	1 459	1 363	1 300	1 347
Industrial[b][c]	4 704	4 853	5 203	5 252	5 323
Transportation	2 577	2 679	2 777	2 758	2 864
Total	**10 173**	**10 416**	**10 753**	**10 680**	**10 976**

(a) Estimates

(b) Includes biomass (wood and pulping liquor)

(c) Includes producer consumption energy use and non-energy use

Source: Statistics Canada, NEB

in 2006 and in 2005. This contributed to strong energy demand growth rates of 5.3 percent for the residential sector and 3.6 percent for the commercial sector (higher demand for services) in 2007.

Robust Canadian economic growth in 2007 contributed to energy demand growth in the commercial and industrial sectors. Canadian GDP was stronger in the first half of the year than in the second half and increased 2.7 percent between November 2006 and November 2007. The goods-producing industries' GDP increased by one percent and the service industries' GDP increased by 3.5 percent. The modest growth in the goods-producing industries' GDP could be the result of overall lower prices in 2007. The Industrial Product Price Index (IPPI) decreased 0.9 percent between December 2006 and December 2007. The largest decreases occurred in prices for motor vehicles and other transport equipment, metal and paper products, while prices for petroleum and coal products increased.

Transportation energy costs increased in 2007. For example, between December 2006 and December 2007 gasoline pump prices increased by 14.9 percent and the price for air transportation rose by 6.2 percent. Despite these higher prices, overall transportation energy consumption is estimated to be 3.8 percent higher in 2007. Motor gasoline sales were up 3.5 percent and diesel sales up 4.9 percent. Population growth and commercial and industrial growth helped push passenger and freight transportation demand higher, showing little, if any, price sensitivity.

2.1 Looking Ahead

There are indications that energy consumption trends could see shifts in several key areas. At a general level, growing anxiety regarding U.S. macroeconomic conditions, energy price concerns, potential supply constraints and heightened environmental awareness could influence consumer spending habits and therefore energy demand trends.

Government programs and policies could also impact energy demand trends over the next few years. Several significant energy and environment policies were confirmed or tabled at the provincial and federal level. The federal government's expanded portfolio of ecoAction initiatives includes energy efficiency for buildings, appliances and vehicles. Legislation has been passed for updates on the Model National Energy Code for Buildings. In addition, an expanded labelling program is ready for rollout. For electrical appliances and electronics, an expanded and more rigorous suite of appliance energy performance standards have been issued. New regulations are pending for lighting and electrical standby power limits.

A significant proposal is the Regulatory Framework for Greenhouse Gas Emissions. In the near term (2007-2010) this includes a six percent per year improvement in emission intensity for major industries, giving an enforceable 18 percent reduction from 2006 emission intensity in 2010. These reductions could be achieved in part through energy efficiency improvements.

Several provinces have released energy plans, with targets, that address energy efficiency, energy conservation and renewable energy. One common element on the efficiency side is heightened building energy performance standards that could lead to improvements in baseline new building performance in many areas of the country. As well, ethanol regulations in various Canadian provinces are likely to bring about a shift in hydrocarbon fuel consumption trends.

Finally, changes to consumer preferences could also have an impact on energy demand trends in Canada in the longer term. Multi-family dwellings are increasing their share of households in Canada. In 2007, the share of multi-family dwelling construction was 50.9 percent – the largest since 1982 (51.5 percent). This could have a direct impact on residential energy demand in the future, as well as a possible indirect impact on passenger transportation energy demand.

Upstream Oil and Gas Activity

Measurement of upstream oil and gas activity includes acquisition of land rights, seismic programs, number of active drilling rigs, wells drilled and the capital expenditures involved.

Cost pressures associated with strong economic growth continued in 2007. Also adding to the cost is the trend in mature resource basins of new wells producing at lower rates and recovering less energy. Over the course of the year, crude oil prices gained sufficient strength relative to these costs to cause oil-related activity in Saskatchewan and Alberta to remain fairly strong. Conversely, natural gas prices remained stubbornly flat in the first half of the year before slipping further in the fall. The combination of rising costs and flat to declining prices eroded the economics of some of Western Canada's natural gas opportunities and caused investment to either be deferred or transferred to oil projects or to U.S. gas producing regions. In 2007, growth and escalating costs in oil sands projects required additional capital spending and may have diverted some investment from other oil and gas operations.

In a tightly balanced North American natural gas market, any pullback in Canadian drilling activity would be expected to lead to reduced production and eventually to higher prices, thereby providing the incentive to resume higher drilling levels. However, in 2007, mild temperatures, higher LNG imports and rising U.S. unconventional gas production offset any losses in Canadian output and prevented a sustained rise in prices that might have provided the incentive for increased Canadian drilling activity.

Drilling capacity in Western Canada continued to increase as new rigs commissioned during the 2005-06 period of peak drilling were added to the fleet. By the end of 2007, the size of the drilling fleet had grown to 897 rigs compared to 842 at the end of 2006.[1] On average, there were 339 drilling rigs operating per month in western Canada compared to an average of 473 in 2006. Figure 3.1 provides the weekly active rigs in Western Canada.

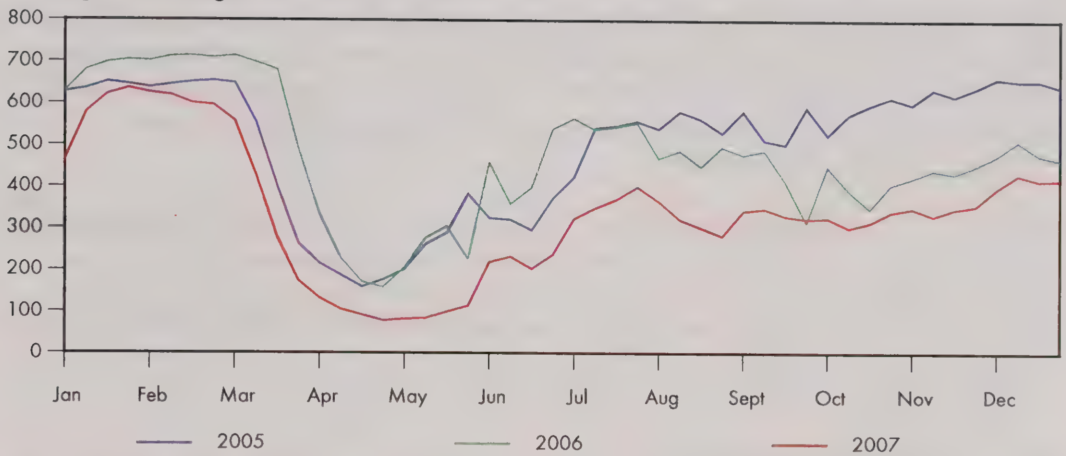
As shown in Figure 3.2, just over 18,000 wells were drilled in Western Canada in 2007. This is roughly 4,600 less than in 2006. The number of oil wells drilled in the year declined by six percent, with natural gas drilling down by 25 percent. As a result of the ongoing decline in gas economics relative to oil, the percentage of wells directed to natural gas slid to 68 percent from 73 percent in 2006.

Both U.S. gas and oil drilling were maintained at high levels throughout 2007 and contributed to an estimated three percent increase in U.S. gas deliverability as U.S. operations were less impacted by rising costs and declining well productivity. Rising unconventional gas production in the Rockies and south central states provided much of the increase with additional volumes from the start up of a Gulf of Mexico deep water development late in the year.

1 Canadian Association of Oilwell Drilling Contractors, Average Monthly Drilling Rig Count - Western Canada, www.caodc.ca/rigcountspg3.htm#mthdrill

FIGURE 3.1

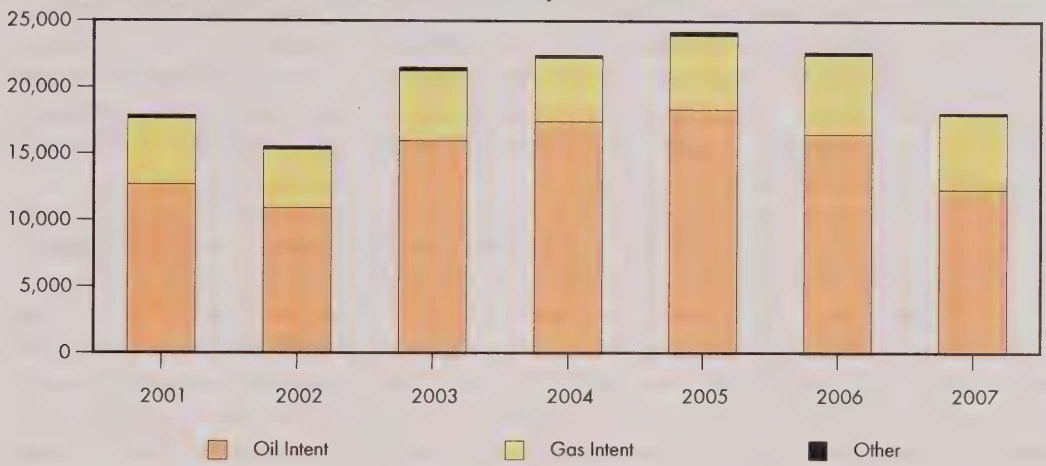
Weekly Active Rigs in WCSB



Source: Nickle's Daily Oil Bulletin

FIGURE 3.2

Number of Wells Drilled – Western Canada, 2001 - 2007



Source: NEB

With major land positions in the oil sands areas now established, land rights acquisition were scaled back in 2007. Total land sale payments in Western Canada were $2.66 billion, down 37 percent from the $4.19 billion paid in 2006. The moderation in oil sands land requirements represented over 85 percent of the reduction with sales of $0.65 billion over the year compared to $1.96 billion in 2006. The average price for oil sands land dropped by more than half to average just $573 per hectare compared with the $1,273 paid in 2006. Land not associated with oil sands continued to be of interest and was purchased at an average price of $697 per hectare, above the $549 paid in 2006. Areas in British Columbia with shale gas potential were of particular interest. A major purchase of exploration rights in the Beaufort Sea increased commitments for future drilling in the Northwest Territories by $613 million in 2007 compared to a $52 million increase in 2006. Acquisition of drilling rights in the Yukon, Newfoundland and New Brunswick amounted to $20 million, $1.5 million and $1.6 million, respectively, which is down from 2006 levels.

In December 2007, the *Canadian Oil and Gas Operations Act* (COGOA) was amended to give the NEB increased responsibility over pipelines in the frontier regions. In particular, it gave the

Board jurisdiction over traffic, tolls and tariffs. As a consequence of these changes, there were also amendments to the *Canadian Petroleum Resources Act* and the *National Energy Board Act*.

In 2007, the Canadian industry turned away from exploration activity with exploratory well completions down by 33 percent compared with 2006. Seismic survey activity in Western Canada during 2007 also fell markedly from the previous year with the average number of active crews dropping from 14.1 to 5.8. The significant drop in seismic activity signals that a recovery in exploration activity in 2008 is unlikely.

Total oil and gas capital expenditures in Canada fell by 10 percent in 2007 to an estimated $48 billion. Capital spending associated with oil sands projects is estimated to have jumped by 18 percent to $17 billion. Capital spending in all other areas of the industry dropped by an estimated 20 percent. During 2007, there was a shift in spending away from natural gas and toward oil, in recognition of the more attractive economics resulting from high oil prices.

3.1 Looking Ahead

Improving cost control has become a key objective for oil sands development. To reduce the likelihood of major cost overruns, proponents are investing more in front-end engineering and design (FEED) before initiating construction. A key component of this front-end work is employing more drilling rigs to drill additional test holes to better define the resource. Large capital expenditures are planned for oil sands projects in 2008 and will likely continue to divert some investment from conventional activities. At the same time, a joint industry-stakeholder group is calling on government to enact a partial moratorium on oil sands development in certain ecologically sensitive areas of the Athabasca region. The group has urged the government to suspend land lease sales in the affected areas until 1 January 2011.

Despite the likelihood of increased oil sands expenditures, overall 2008 capital spending in Canada's upstream oil and gas industry is expected to be down at least three percent from 2007. The most recent drilling forecast for 2008, which is from the Petroleum Services Association of Canada (PSAC), is particularly negative for natural gas activity in Western Canada with oil drilling projected to exceed natural gas drilling for the first time since 1997. Under the PSAC scenario, the number of gas wells drilled in 2008 in Western Canada could fall by a third from the already reduced level of 2007. Should natural gas prices increase somewhat through higher demand associated with more extreme weather and perhaps lower LNG imports, the shift from natural gas to oil may be less pronounced.

With reduced natural gas drilling in 2008, Canadian natural gas production will be lower than in 2007. Even with slightly higher drilling in 2008, conventional and heavy crude oil production is likely to continue to trend downward. While oil sands production is forecast to increase, conventional light and heavy crude oil production will continue their natural annual decline of roughly three percent.

Crude Oil

4.1 International Markets

In 2007, crude oil prices started the year significantly lower than the record $78 per barrel (intraday high) reached in July 2006. In January, the average price of crude oil was just over $54 per barrel. Continuing the trend of high and volatile energy markets, crude oil prices climbed by 76 percent and by year-end were approximately $96. With the appreciation of the Canadian dollar versus the U.S. dollar the percentage rise in the price of crude oil was less in Canada. The average price of crude oil in 2007 was around $72 per barrel.

Lower crude oil prices at the beginning of the year reflected mild weather across North America, continuing from the fourth quarter of 2006, as well as above normal petroleum product inventory levels and difficulties among the Organization for Petroleum Exporting Countries (OPEC) members in reducing their production. The subsequent rise in the price throughout the year was a result of geopolitical risks in Iraq, Nigeria, Iran and other producing regions; robust oil demand growth; increasing finding and development costs; continuing tight production and refining capacity; and the depreciating American dollar. In addition, OPEC's goal of reducing inventory levels by implementing production cuts was eventually successful, thereby limiting downward price pressure.

The year 2007 witnessed a number of key events that shaped the crude oil market. Mid-January and February brought colder than normal temperatures in key heating regions. This had the effect of drawing down inventories of petroleum products and crude oil from their maximum levels at the beginning of the year to below five-year averages by year-end. In March, WTI became disconnected from the rest of the world because of the influx of Canadian crude oil supply into Cushing, Oklahoma, a key pricing hub. This resulted in WTI trading at a discount to North Sea Brent and in early April this discount reached a record $6.37 per barrel. Historically, WTI has traded at a slight premium to Brent as shown in Figure 4.1.

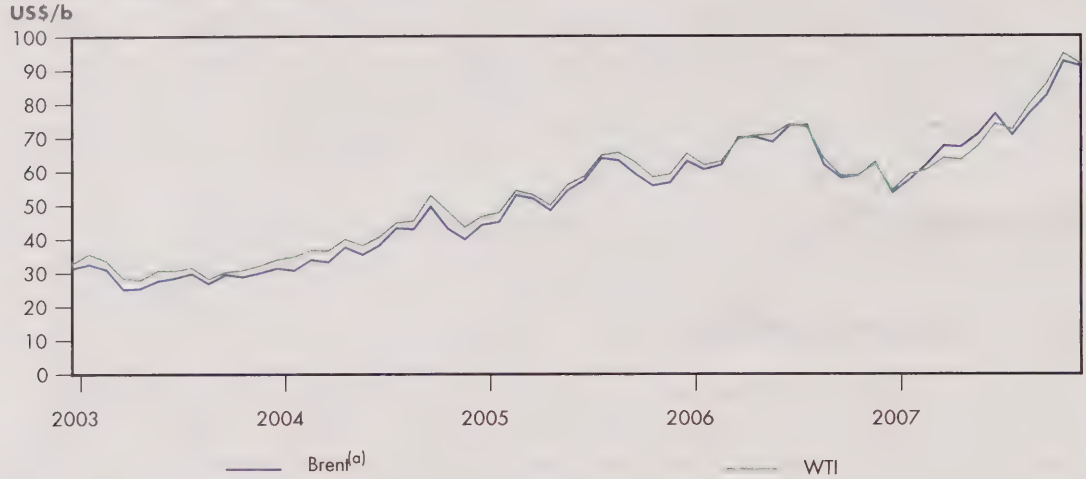
Prices rose through the summer and fell with the onset of the hurricane season; however, despite the forecast of above average hurricane activity, there was no major damage or production losses.

Prices peaked in November with crude oil rising to a record $99.29 per barrel on the NYMEX. In the fourth quarter 2007, seasonal weather in key markets contributed to strong demand growth and resulted in the largest inventory decline in the U.S. since 1999. Year-end geopolitical events including, sabotage to oil infrastructure in Nigeria also pushed prices up in late December.

The U.S., the largest consumer of crude oil and Canada's most important trading partner, struggled with a weak currency, the sub-prime mortgage crisis and the ongoing large cost of the war in Iraq. The weakness in the U.S. dollar was instrumental in supporting oil demand growth outside of the U.S. because it made crude oil more affordable in countries with stronger currencies. Oil demand

FIGURE 4.1

WTI and Brent Oil Prices, 2003 - 2007



(a) Brent is the common benchmark for European crude oil pricing

Source: International Energy Agency

growth in developing countries continued to put added pressure on the ability of both OPEC and non-OPEC countries to supply enough of the right grades of crude oil to the market.

OPEC met three times during 2007. At its 15 March 2007 meeting in Vienna, OPEC agreed to extend its existing agreement which called for production cuts of 1.7 MMb/d (1.2 MMb/d in November 2006 and 500 Mb/d in February 2007). Speculation was that the reduction was actually 1.0 MMb/d. OPEC met on 11 September and announced that it would raise production by 500 Mb/d effective 1 November to meet rising winter demand in the northern hemisphere. By this time, crude oil prices had already risen to well over US$77 per barrel. At its meeting on 5 December, OPEC announced that it would leave production unchanged; in response, crude oil prices rose to $90 per barrel. OPEC also indicated that it would continue to monitor the market and meet again on 1 February 2008 and 5 March 2008.

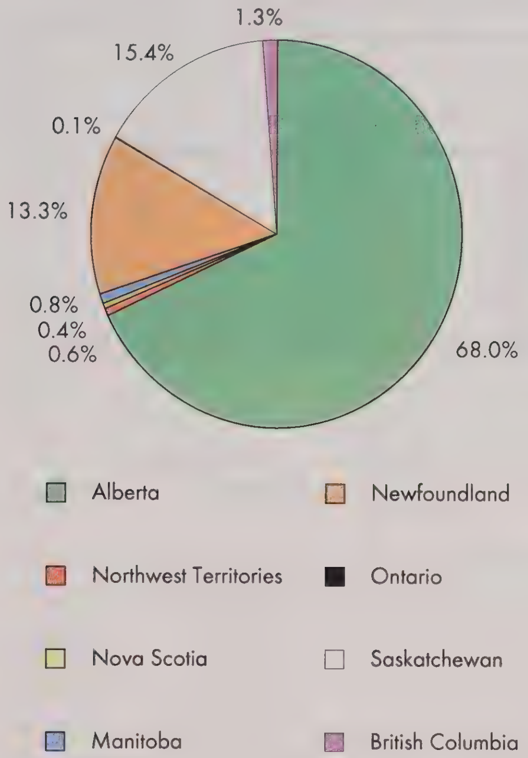
4.2 Canadian Oil Production and Reserves Replacement

In 2007, Canadian production of crude oil and equivalent averaged 441 128 m^3/d (2.8 MMb/d), an increase of seven percent from 2006 levels. This increase primarily reflects growing oil sands production from both in situ and surface-mining projects. As well, Canada's East Coast offshore production increased by 16 percent, reflecting an improvement in operational performance at the Terra Nova and White Rose fields compared with the previous year. Figure 4.2 illustrates crude oil production by province.

In 2007, production offshore Newfoundland and Labrador was 58 579 m^3/d (369 Mb/d). In Western Canada, crude oil and equivalent supply increased by four percent because of the increase in production from the oil sands. Conventional light crude oil production declined by three percent, reflecting the continuing decline of mature light oil reservoirs in the WCSB. This decline was significantly less than the long-term trend of five percent, because strong crude oil prices resulted in increased oil drilling, thereby slowing the rate of decline in the WCSB. Conventional heavy crude oil production levels also decreased by three percent, in line with the general decline that has developed since the production peak in 2001. Figure 4.3 illustrates crude oil production by type.

FIGURE 4.2

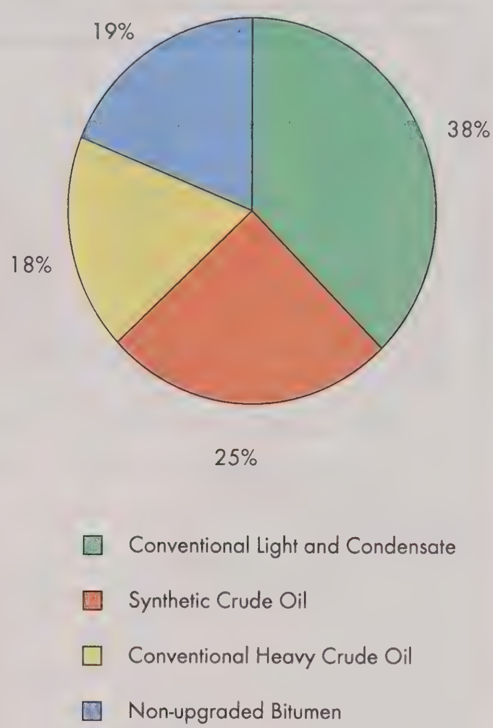
Crude Oil and Equivalent Production by Province



Source: NEB

FIGURE 4.3

Crude Oil and Equivalent Production by Type



Source: NEB

Despite the fact that remaining conventional established reserves are reduced by production each year, new discoveries, extensions to existing pools and revisions to reserve estimates in existing pools offset declines to reserve estimates. From 2002 to 2006, cumulative additions of conventional light and heavy crude oil to established reserves replaced 92 percent of production (Table 4.1).

The NEB's estimate of total remaining Canadian conventional crude oil and crude bitumen reserves at year-end 2006 (the last year for which there is mostly complete data available) is 32.5 billion cubic metres (205.1 billion barrels), an increase of less than one percent compared with 2005 (Table 4.2). Estimates of remaining established conventional crude oil reserves in Canada decreased by eight

TABLE 4.1

Conventional Crude Oil Reserves, Additions and Production, 2002-2006 (million cubic metres)

	2002	2003	2004	2005	2006	Total
Additions[(a)]	88.1	60.8	66.9	134.7	27.0	377.5
Production	81.0	85.6	82.7	78.8	82.1	410.2
Total Remaining Reserves	**690**	**663**	**640**	**696**	**640**	
Total Remaining Reserves (millions of barrels)	**4,342**	**4,172**	**4,027**	**4,382**	**4,033**	

(a) White Rose added in 2002

Source: Provincial Energy Agencies, Offshore Petroleum Boards, NEB

TABLE 4.2

Estimates of Established Reserves of Crude Oil and Bitumen at 31 December 2006 (million cubic metres)

Conventional Crude Oil	**Initial**	**Remaining**
British Columbia[(a)]	125.8	18.2
Alberta[(b)]	2 730.8	250.1
Saskatchewan[(c)]	890.1	170.0
Manitoba[(d)]	45.8	7.7
Ontario[(e)]	14.8	1.6
Northwest Territories, Nunavut and Yukon		
Arctic Islands and Eastern Arctic	0.5	0.0
Mainland Territories - Norman Wells and Cameron Hills	52.9	14.7
Nova Scotia - Cohasset and Panuke[(d)]	7.0	0.0
Newfoundland - Hibernia, Terra Nova and White Rose[(d)]	299.1	177.9
Total	**4 166.8**	**640.2**
Total (millions of barrels)	**26 250.8**	**4 033.3**
Crude Bitumen		
Oil Sands - Upgraded Crude[(f)]	5 590	5 008.0
Oil Sands - Bitumen[(f)]	22 802	22 520.0
Total	**28 392**	**27 528.0**
Total in millions of barrels	**178 870**	**173 426.0**
Total Conventional and Bitumen	**32 558.8**	**28 296.6**
Total Conventional and Bitumen (millions of barrels)	**205 120.8**	**178 268.6**

(a) British Columbia Ministry of Energy & Mines and NEB common database

(b) Alberta Energy Resources Conservation Board (ERCB) and NEB common database

(c) Saskatchewan Reservoir Annual 2004 with NEB estimated update

(d) Provincial Agencies or Offshore Boards, NEB estimate for Manitoba

(e) Canadian Association of Petroleum Producers

(f) ERCB Report – ST 98 2006

(Note: totals may not add because of rounding)

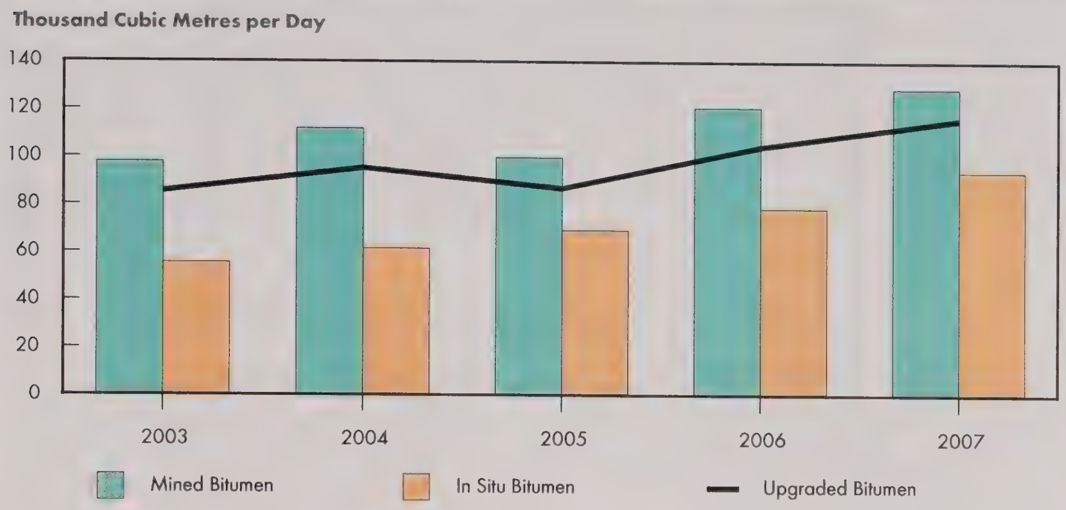
percent to 640.2 million cubic metres (4,167 million barrels) for 2006. Most of this decrease could be attributed to production significantly outpacing reserves additions in 2006. The remaining established crude bitumen reserves decreased slightly to 27.5 billion cubic metres (173.4 billion barrels) reflecting 2006 bitumen production.

4.3 Oil Sands

In 2007, oil sands production continued to expand and attract investment from domestic and foreign sources. Investment in Canada's oil sands is appealing because it is a large resource, Canada has a stable political and investment climate and there are a diminishing number of investment opportunities in other oil producing countries, due in part to increasing resource nationalism. As well, with high crude oil prices, oil sands development becomes more economic than in the past. Oil sands spending in 2007 is estimated to be about $18 billion.

FIGURE 4.4

Crude Bitumen Production, 2003-2007



Source: Energy Resources Conservation Board (ERCB)

The fiscal environment for oil sands changed in the fourth quarter of 2007 with adjustments to Alberta royalties as well as changes to federal taxation measures. Royalty rates will now be determined by a sliding scale based on WTI prices, expressed in terms of real Canadian dollars. At prices up to Cdn$55 per barrel, royalty rates will actually remain identical to the previous royalty scheme, at one percent pre-payout and 25 percent post-payout. At prices above this point, rates would increase reaching a maximum of nine percent pre-payout and 40 percent post-payout at WTI $120 per barrel. All royalty payments will remain both tax deductible and eligible as expenditures for the purposes of calculating payout. The federal government announced cuts to corporate income tax rates, from 22.1 percent in 2007 to 15 percent in 2012. Industry analysts indicate that the net effect of changes to the Alberta royalty framework and federal tax changes will be neutral to moderately positive.

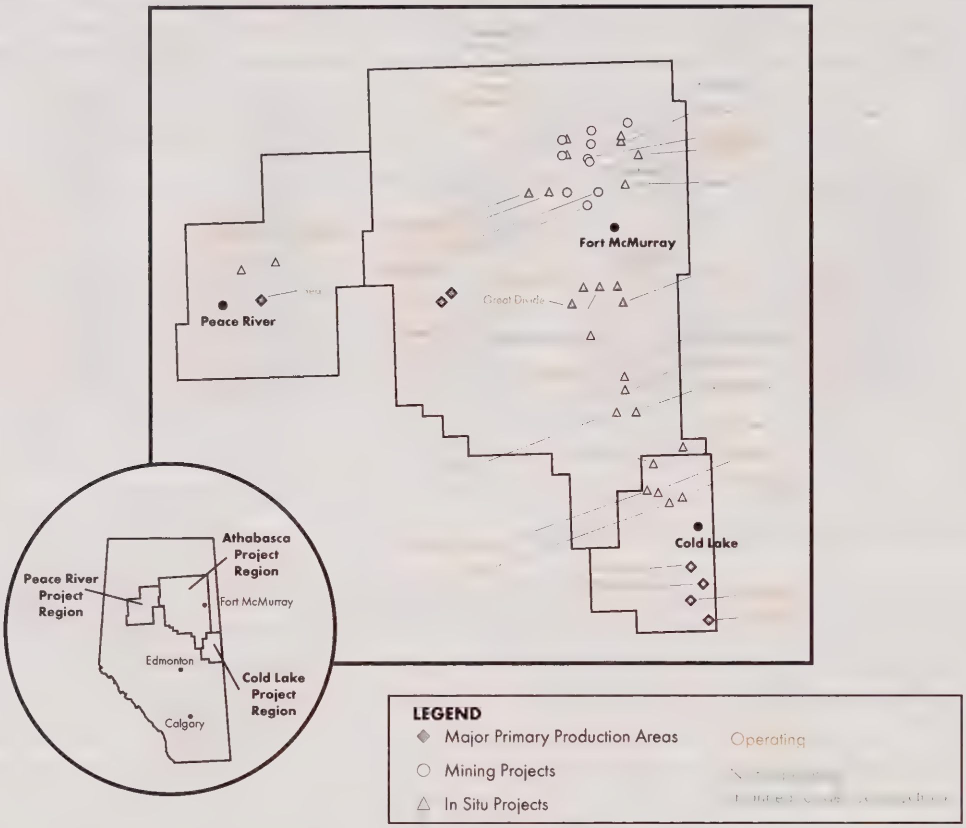
In 2007, bitumen production from mining and in situ operations totalled 223 000 m^3/d (1.4 MMb/d), an increase of 13 percent compared with 2006. In situ bitumen production increased by 20 percent to 94 000 m^3/d (592 Mb/d) (Figure 4.4). Two major in situ projects started up in 2007, the Surmont SAGD Project operated by ConocoPhillips and Total E&P Canada as well as the OPTI/Nexen Long Lake SAGD/Upgrader project (Figure 4.5). Bitumen from mining operations increased by nine percent to 129 000 m^3/d (813 Mb/d) and upgraded bitumen production increased by 11 percent to 104 600 m^3/d (659 Mb/d).

At Syncrude, upgraded bitumen production in 2007 reflected incremental volumes from the expanded Stage 3 facilities, which were operational throughout the year. However, this increased production was partially offset by unplanned maintenance on Coker 8-2 during the first quarter and planned maintenance on other units, including a turnaround of the LC-Finer. Further reductions occurred in the fourth quarter with Coker 8-3 outages that suspended production for approximately one week at the beginning of October and in early December. During the third quarter of 2007, Syncrude made the transition to producing the higher quality Syncrude Sweet PremiumTM (SSP) blend, with all production in the fourth quarter reflecting this switch. Syncrude production averaged 48 400 m^3/d (305 Mb/d), up by 15 percent from 2006.

At Suncor, oil sands production averaged 37 400 m^3/d (236 Mb/d) in 2007, compared with 41 300 m^3/d (260 Mb/d) in 2006. This decrease primarily reflects the impact of scheduled and unscheduled maintenance, which included a scheduled 50-day maintenance shutdown to portions of

FIGURE 4.5

Major Oil Sands Project Locations



In Situ Projects	***Operator***
Kirby	Canadian Natural Resources
Wolf Lake/Primrose	Canadian Natural Resources
Surmont	ConocoPhillips/Total
Great Divide	Connacher Oil and Gas
UTF (Dover)	Devon Energy
Jackfish Creek	Devon Energy
Christina Lake	EnCana
Foster Creek	EnCana
Caribou	Husky Energy
Sunrise	Husky Energy
Tucker Lake	Husky Energy
Cold Lake	Imperial Oil
Hangingstone	Japan Canada Oil Sands (JACOS)
Christina Lake	MEG
Long Lake	OPTI/Nexen Canada
White Sands	Petrobank
Lewis	Petro-Canada
MacKay River	Petro-Canada
Meadow Creek	Petro-Canada/Nexen
Peace River	Shell Canada
Firebag	Suncor Energy
Joslyn Creek	Total E&P Canada
Cadotte Lake	Shell
Orion	Shell

Mining Projects	***Operator***
Muskeg River	Albian Sands (Shell/Chevron/Western Oil Sands)
Jackpine Mine	Albian Sands (Shell/Chevron/Western Oil Sands)
Horizon*	Canadian Natural Resources
Kearl Lake	Imperial Oil
Suncor Base Mine	Suncor Energy
Millennium	Suncor Energy
Syncrude Base Mine	Syncrude Joint Venture
Aurora	Syncrude Joint Venture
Northern Lights	Synenco
Fort Hills	Petro-Canada/UTS Energy/Teck Cominco
Joslyn Creek	Total E&P Canada

Major Primary Production Areas

SEAL
Pelican Lake
Lindbergh
Frog Lake
Brintnell
Bonnyville
Beaverdam

* Includes plans for both in situ and mining

Source: NEB

Suncor's oil sands operation to tie in new facilities related to a planned expansion. Also affecting oil sands throughput were issues at Suncor's Firebag in situ operation which provides feedstock to the upgrading operations, where high levels of odorous emissions have resulted in an intervention by both Alberta Environment and the Alberta Energy and Utilities Board (EUB). Until emissions are reduced,

production at Suncor's in situ operation has been capped by regulators at approximately 6 700 m^3/d (42 Mb/d) of bitumen.

Production at the Athabasca Oil Sands Project (AOSP) was disrupted by a 19 November fire that damaged one of two residue hydro-conversion units at the Scotford Upgrader, when a leak occurred and the vapour ignited. AOSP officials decided to move forward the planned maintenance for the upgrader and the associated Muskeg River mining complex which provides bitumen to the upgrader. One production train at the upgrader and the Muskeg River mine were in operation by year-end, with the restarting of the second production train completed in mid-January. Production for the year is estimated at 23 900 m^3/d, three percent above 2006 levels.

4.4 Crude Oil Exports and Imports

In 2007, crude oil exports averaged 294 411 m^3/d (1.85 MMb/d) which represents a year-on-year increase of three percent. Light crude oil exports, which include pentanes plus and synthetic crude oil (upgraded bitumen), represented 38 percent of all exports with the remaining 62 percent being exports of heavy crude oil.

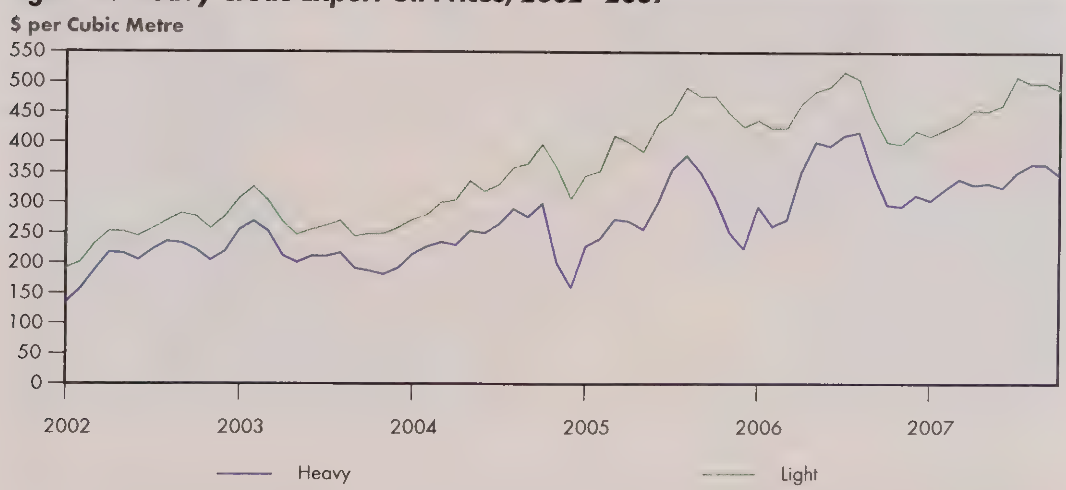
The estimated value of crude oil exports for 2007 is $41.2 billion compared with $39.3 billion in 2006. The estimate is based on projected export prices of $460 and $337 per cubic metre ($73 and $54 per barrel) for light crude oil and heavy crude oil, respectively (Figure 4.6).

Heavy and light crude oils are traded in separate markets and accordingly, the prices for each vary as a result of the supply and demand for each crude type. Heavy crude has a smaller market and has higher refining costs and is usually discounted. The light–heavy price differential varies as a function of market conditions in each market. Extraordinary circumstances aside, the differential typically narrows in the summer months because of the higher demand for heavy crude oil during asphalt season and widens again in September.

On a dollar basis, the light–heavy differential or "heavy crude oil discount" averaged $153 per cubic metre ($24 per barrel) during 2007 with a sustained fourth quarter average of $199 per cubic metre ($30 per barrel). At one point in the fourth quarter, the heavy crude oil discount reached $284 per

FIGURE 4.6

Light and Heavy Crude Export Oil Prices, 2002 - 2007



Source: NEB

cubic metre ($45 per barrel) due in part to refinery problems in the U.S. PADD II market, which is a key market for heavy crude oil.

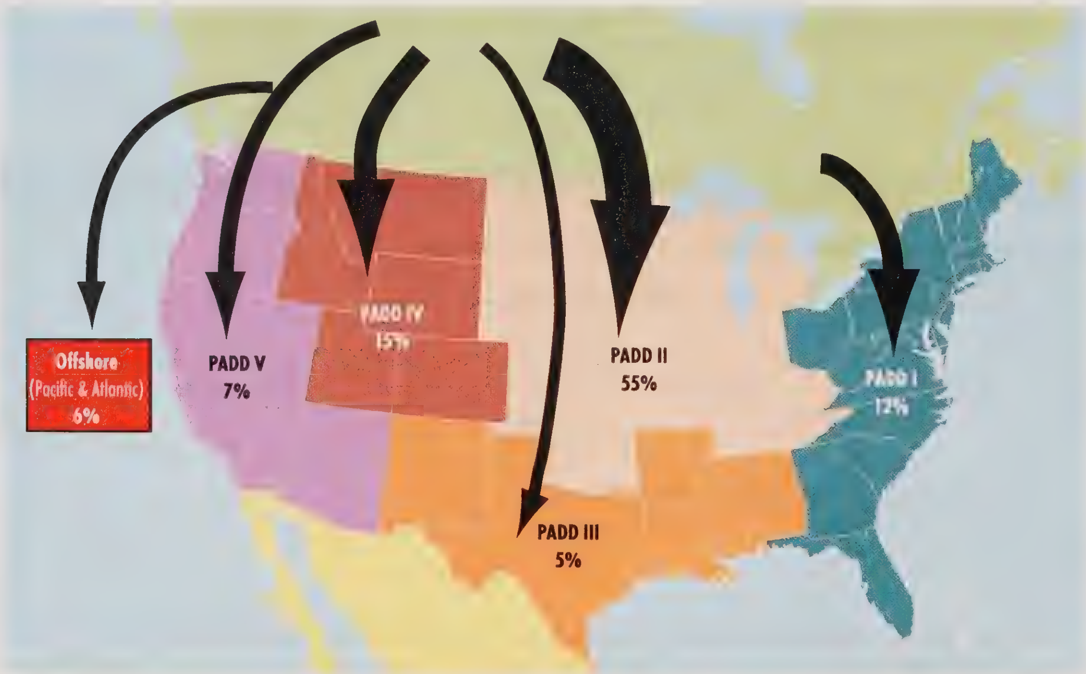
Capacity constraints on the three major oil export pipelines also contributed to the widening differential. The Enbridge and the Express/Platte systems were operating near capacity throughout 2007 forcing Canadian heavy crude oil producers to seek other markets for their crude oil. Trans Mountain was therefore over nominated most of 2007 as producers tried to transport their crude oil to the west coast. With the pipelines at capacity or under apportionment, there was a glut of Canadian heavy crude oil putting downward pressure on prices and contributing to the widening differential. In the short term, this situation is expected to continue to be driven by increases in oil sands production.

A number of pipeline applications were prepared and submitted to the Board in 2007. Enbridge submitted their Southern Lights, Alberta Clipper and Line 4 Extension applications which aim to expand system capacity in order to meet future production increases. The Canadian portion of TransCanada's 69 200 m^3/d (435 Mb/d) Keystone application (OH-1-2007) was approved by the Board in September 2007 and a subsequent application for extension to Cushing, Oklahoma was received in November. Enbridge's Southern Lights (OH-3-2007) and Alberta Clipper (OH-4-2007) applications were approved by the Board in the first quarter of 2008.

Canada remained the number one supplier of crude oil to the U.S. followed by Saudi Arabia and Mexico.[2] Saudi Arabia moved ahead of Mexico into the number two position during 2007. According to the Energy Information Administration (EIA) the U.S. imported on average 1.6 million m^3/d (10.0 MMb/d) with Canada supplying approximately 297 000 m^3/d (1.87 MMb/d). Over half

FIGURE 4.7

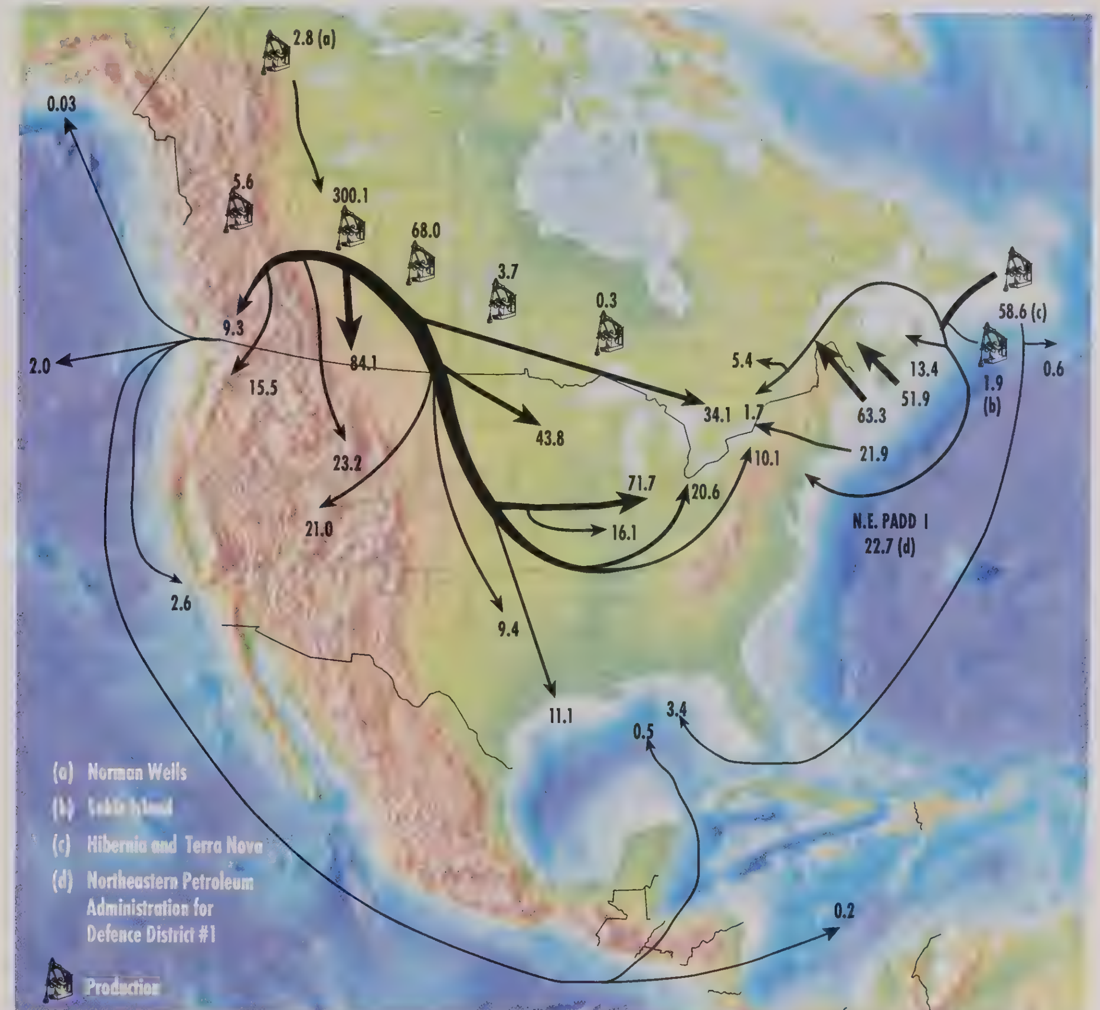
Deliveries of Canadian Crude Oil in 2007 (percent)



2 Canada accounted for 18.7 percent of U.S. imports, Saudi Arabia accounted for 14.5 percent and Mexico accounted for 14.1 percent.

FIGURE 4.8

Crude Oil Supply and Disposition – 2007 (thousand cubic metres per day)



(55 percent) of Canadian crude exports went to the U.S. Midwest (PADD II) market in 2007 making it the largest consuming region for Canadian crude oil (Figure 4.7, Figure 4.8).

Offshore eastern Canadian production continued to supply U.S. consumers. In 2007, over 81 percent of eastern Canadian crude oil exports were delivered to the U.S. east coast (PADD I). The remaining eastern Canadian exports were delivered to the U.S. Gulf Coast (16 percent) and the United Kingdon (3 percent).

Although Canada is a net crude oil exporter, imports still account for a significant portion of Canadian refinery demand. Refineries located in Ontario, Quebec, and Atlantic Canada source a portion of their crude oil from abroad, while western Canadian refineries are fully supplied by domestic production and do not import crude oil. In 2007, crude oil imports are estimated at 144 344 m³/d (909 Mb/d). This is an increase of six percent compared with 2006 and represents 48 percent of total Canadian refinery feedstock. OPEC countries supplied 49 percent of imported crude oil and 38 percent was delivered from the North Sea. The remaining 13 percent was split between North American producing nations (U.S. and Mexico) and other countries. In 2007, 80 percent of the Atlantic refining requirements were met by imports and the remaining 20 percent were met with

eastern Canadian production. Quebec remained the largest regional importer of crude oil with 92 percent of their refining needs supplied from international sources. Ontario accounted for the remainder of imported crude volumes. Ontario refineries are increasingly sourcing crude oil supplies from Western Canada.

4.5 Oil Refining

There were 19 Canadian refineries operating at the end of 2007 with a total refinery capacity (distillation) of 324 500 m^3/d (2 MMb/d). The refineries and their locations are included in Table 4.3.

Canadian demand for petroleum products in 2007 is estimated at 281 960 m^3/d (1.77 MMb/d), an increase of 2.9 percent compared with 2006, reflecting the strong performance of the Canadian economy during the year. Refinery runs of crude oil in Canada in 2007 are estimated at 290 250 m^3/d (1.83 MMb/d), an increase of 1.6 percent over 2006 levels of 285 470 m^3/d (1.80 MMb/d). Capacity utilization also increased from 88.2 percent in 2006 to 89.7 percent in 2007. Refinery receipts of domestic crude oil grew 3.5 percent in 2007 to 153 500 m^3/d (965 Mb/d), with Western Canada

TABLE 4.3

Refineries in Canada

Company	Location	Capacity (m^3/d)	Capacity (b/d)
Atlantic Canada		**75 200**	**473,800**
Imperial Oil Limited	Dartmouth, N.S.	14 000	88,200
Irving Oil Limited	Saint John, N.B.	44 500	280,400
North Atlantic Refining (Harvest Energy)	Come-by-Chance, Nfld.	16 700	105,200
Quebec		**74 400**	**468,700**
Petro-Canada	Montreal	20 700	130,400
Shell Canada Limited	Montreal	20 700	130,400
Ultramar Limited	St. Romuald	33 000	207,900
Ontario		**74 400**	**468,700**
Imperial Oil Limited	Nanticoke	17 800	112,100
Imperial Oil Limited	Sarnia	19 300	121,600
Shell Canada Limited	Sarnia	11 100	69,900
NOVA Chemicals	Sarnia	12 700	80,000
Suncor Energy Products Inc.	Sarnia	13 500	85,100
Western Canada		**100 500**	**633,200**
Consumers Co-operative Refineries Ltd.	Regina, Sask.	13 500	85,100
Husky Energy Marketing Inc.	Lloydminster, Alta.	4 000	25,200
Imperial Oil Limited	Strathcona, Alta.	28 600	180,200
Moose Jaw Asphalt	Moose Jaw, Sask.	2 400	15,100
Petro-Canada	Edmonton, Alta.	21 900	138,000
Shell Canada Limited	Scotford, Alta.	20 000	126,000
Chevron Canada Limited	Burnaby, B.C.	8 300	52,300
Husky Energy Marketing Inc.	Prince George, B.C.	1 800	11,300
Total		**324 500**	**2,044,400**

Source: NEB

domestic receipts offsetting a reduction in eastern Canada receipts as a consequence of reduced production at Hibernia during February. Refinery receipts during 2007 were higher reflecting increased demand for crude oil from Canadian refineries, particularly in Quebec and the Atlantic Provinces, with smaller increases in Western Canada.

4.6 Main Petroleum Product Exports and Imports

Canada continued to be a net exporter of petroleum products, with the U.S. as its main destination. Exports of main petroleum products in 2007 are estimated to be 71 340 m^3/d (448.7 Mb/d), an increase of six percent compared with 2006. Increased availability of refined products in Canada, combined with tight refinery capacity in U.S. were the main drivers for this increase. Canadian imports declined by seven percent to 43 080 m^3/d (271.0 Mb/d) compared with 2006 also reflecting the reduced need for imports due to increased domestic supply of refined products. Exports to the U.S. were mainly to the East Coast (65 percent), followed by the U.S. Midwest and the U.S West Coast.

The estimated revenue in 2007 from main petroleum products, including partially processed oil, was $9.2 billion, up from $6.7 billion in 2006. Strong demand for gasoline and diesel fuel, rising crude oil prices and an unusual wave of refinery outages in U.S. and Canada boosted product prices during the first part of the year. Very high crude oil prices and low gasoline inventory levels supported gasoline prices most of the year. Distillate inventories remained near the middle of historical levels, but prices reached historical records at the end of the year.

TABLE 4.4

World Oil and Canadian Products Prices (cents per litre)

	2007	2006	Change	Total
Gasoline	97.7	101.8	+4.1	4.2
Diesel	97.1	101.1	+4.0	4.2
Furnace oil	82.5	86	+3.5	4.2
US$/b				
WTI (Cushing. OK)	66.05	72.34	+6.29	9.5
Edmonton Par	71.4	64.34	+7.06	11.0

Source: Fuel Focus Annual Review 2007 NRCan and Energy Information Agency

4.7 Product Prices

According to Natural Resources Canada (NRCan)[3], average Canadian retail product prices were approximately 4.2 percent higher in 2007 compared with 2006, reflecting increases in world crude oil prices. Retail gasoline prices in Canada increased from 98 cents/litre in 2006 to 101.8 cents/litre in 2007, with diesel fuel and furnace oil showing similar increases (Table 4.4). The price escalation in world crude oil markets had a lower than expected impact on Canadian retail prices of gasoline, diesel fuel and heating oil, as the strength of the Canadian dollar helped to offset higher crude oil prices, which are denominated in U.S. dollars.

Gasoline prices increased during the first half of 2007 because of a tight supply–demand balance in North America. Heavier than expected spring refinery maintenance combined with a number of refinery problems pushed gasoline inventories in the U.S. to low levels. In Canada, an unplanned outage at Imperial's Nanticoke refinery in February, combined with a strike at CN rail caused shortages of gasoline and diesel fuel in Ontario and Quebec. The tight gasoline balance in North American markets eased in September with the return of refineries from maintenance and the end of the summer driving season. Distillate fuels (heating oil and diesel) had adequate supply during the winter, with the exception of Western Canada, where a fire at the Shell Scotford upgrader in November contributed to product supply tightness in Western Canada.

3 Fuel Focus, 2007 Annual Review, NRCan, 11 January 2008

4.8 Looking Ahead

Crude oil prices continue to climb to record highs. This rise in crude oil prices has been driven by expectations of continued strength in global demand and geopolitical tensions in Nigeria and Venezuela. In addition, the continuing decline of the U.S. dollar is attracting investors to commodity markets, including crude oil. The global oil markets are pushing oil prices higher to slow global oil demand in a supply-constrained market. High crude oil prices in countries that import crude oil, such as the U.S., drives up inflation and slows economic growth. In Canada, the appreciation of the Canadian dollar versus the greenback has had a positive effect by making American manufactured goods less expensive and softens the increase in the price of gasoline. However, an appreciating Canadian dollar has hurt Canadian manufacturers and other sectors that rely on petroleum products for their operations, raising their input costs. Other key uncertainties this year will be the weather and the state of the U.S. economy.

In 2008, Canadian crude oil production is expected to increase to 443 000 m^3/d (2.8 MMb/d) or 2.2 percent compared with 2007 levels, led by two major oil sands projects. The CNRL Horizon project, which features surface mining and upgrading, is scheduled to start operations mid-year. The Opti/Nexen Long Lake project, which features in situ SAGD extraction and upgrading, is also due to start the upgrading portion by mid-year, with the in situ production initiated in late 2007. Decline rates for conventional crude oil in the WCSB are expected to be moderate based on relatively higher levels of oil drilling and the success of the Bakken oil play in southeast Saskatchewan and southwest Manitoba.

Refineries

In the last several years there have been a number of announcements concerning refinery expansions and the construction of new refineries. In this regard, there has been little done in the past year; however, 2008 could witness more action on this front. Most of the announced projects are located in the Atlantic region, but new capacity is also being considered for Ontario and Western Canada (Table 4.5).

TABLE 4.5

Proposed Refinery Expansions in Canada

Company	Location	Capacity (m^3/d)	Capacity (b/d)	Estimated Completion
Atlantic Canada		**95 200**	**600,000**	
Newfoundland and Labrador Refinery Corp.	Placentia Bay, Nfld	47 600	300,000	2010-2011
Irving Oil	St. John, N.B.	47 600	300,000	2015
Quebec		**6 400**	**40,000**	
Ultramar Limited*	St. Romuald	6 400	40,000	2008
Ontario		**23 800**	**250,000**	
Shell Canada Ltd.	St. Clair	23 800	250,000	2013
Western Canada		**4 700**	**30,000**	
Consumers Co-operative Refinery Ltd.*	Regina, Sask.	4 700	30,000	2012
Total		**130 100**	**920,000**	

* Expansion

In the Atlantic region, refiners have taken advantage of their favourable location being close to the huge U.S. east coast market and with easy access to both imported and domestic crude oil. This has enabled refiners in this region to build sizeable export-oriented refineries. Recently, growing demand in the U.S northeast and limitations on expanding refinery capacity in the U.S. have made it attractive to increase capacity in Atlantic Canada. In November 2007, Irving Oil submitted its environmental assessment plan to provincial and federal regulators for its Eider Rock Refinery project. The new 47 600 m^3/d (300 Mb/d) refinery, initially proposed in October 2006 would be built near the company's Canaport deepwater crude oil receiving terminal and the existing Irving refinery in Saint John, New Brunswick. The plant's design would allow the flexibility to run a wide variety of crude oil from Canada and overseas, and, at the same time, maximize the production of light products (gasoline, naphtha, jet and diesel fuel), instead of heavier products such as bunker fuel and asphalt. Recently, BP signed a Memorandum of Understanding (MOU) with Irving to work together on the next phase of the project. The project has an estimated cost of between $5 and $7 billion, with an expected in-service date of 2015.

In October, Newfoundland and Labrador Refinery Corporation obtained environmental approval for its proposed $4.6 billion refinery project at Placentia Bay, Newfoundland. Construction on the new refinery with an initial capacity of 47 600 m^3/d (300 Mb/d), would start in the first quarter of 2008, with an expected in-service date of 2011.

In Quebec, Ultramar Ltd. is expanding its crude oil processing capacity by 6 300 m^3/d (40 Mb/d) at its St. Romuald, Quebec refinery, raising total capacity to 41 300 m^3/d (260 Mb/d) by the second quarter of 2008. Petro-Canada also has plans to add a new 4 000 m^3/d (25 Mb/d) deep conversion (coking) unit at its Montreal refinery that would allow it to process incremental volumes of foreign heavy crude oil at the facility. If the company proceeds with the project in 2008, construction would be completed by the end of 2009.

In Ontario, Shell has continued with its plans to build a new 23 800 m^3/d to 31 700 m^3/d (150 to 200 Mb/d) heavy crude oil refinery at St. Clair, near Sarnia, Ontario. The company initiated the environmental assessment for the project under terms already approved by the provincial government in June 2007. If Shell proceeds with the project in 2009, the refinery would be completed in 2013 and would incorporate part of the existing Sarnia facility. In December 2007, Suncor announced that the upgrading project at its Sarnia refinery was nearing completion. The new facilities, built at a cost of $960 million, would increase the amount of oil sands crude oil processed at the refinery by up to 6 300 m^3/d (40 Mb/d) and would allow for the production of ultra low sulphur diesel.

In Western Canada, Consumers Co-operative Refineries Ltd. announced in January 2008 a $1.9 billion expansion of its refinery in Regina, Saskatchewan. The project would increase the capacity of the plant from 15 900 m^3/d to 20 600 m^3/d (100 to 130 Mb/d). Pending regulatory approval, the expected in-service date is 2012.

NATURAL GAS

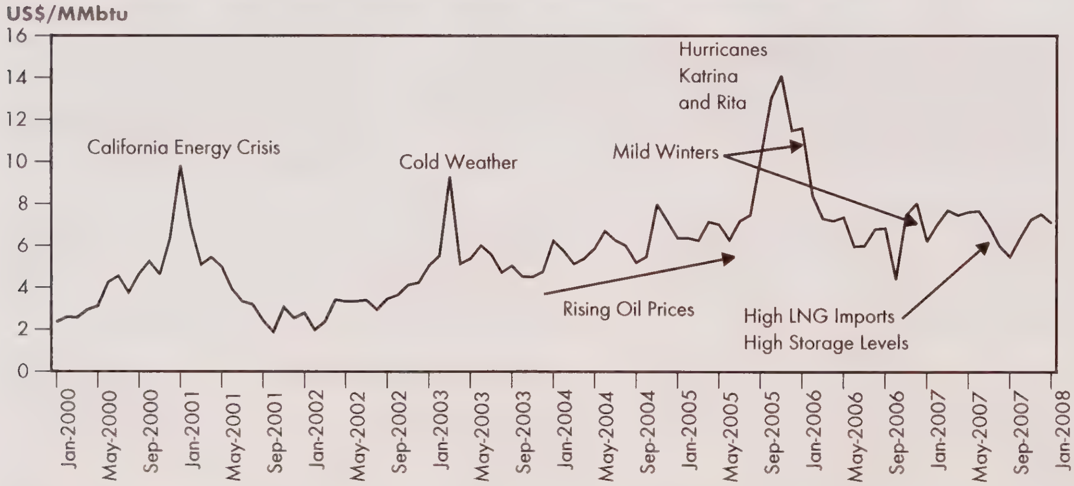
5.1 North American Natural Gas Markets

In 2007, Canada produced about one quarter of the combined natural gas production of Canada and the U.S. Almost 98 percent of Canadian gas is produced from the Western Canada Sedimentary Basin (WCSB) with Alberta producing roughly 79 percent. British Columbia and Saskatchewan contribute roughly 16 and five percent, respectively, of total WCSB production. The Canadian and U.S. natural gas markets operate as one large integrated market. This means that events in any region such as changes in transportation costs, infrastructure constraints or weather will have effects on the other regions. Most Canadian and U.S. natural gas production comes from areas roughly following the continental divide, from the Gulf of Mexico to the Northwest Territories. Demand is spread across the continent but is concentrated in densely populated areas and in areas of intense industrial activity. Canadian gas production is connected to the North American gas market through a network of thousands of kilometres of pipelines that allows buyers to purchase and transport natural gas from a number of supply sources across the continent.

Figure 5.1 shows that natural gas prices have been extremely volatile in recent years. Since 2001, a lack of spare productive capacity in North America has resulted in tight market conditions that have contributed to high and volatile natural gas prices. The price of natural gas is particularly sensitive to real and anticipated weather events and this can result in large swings.

FIGURE 5.1

North American Gas Price Trends – Henry Hub 3-day Average Price



Source: GLJ Publications Inc.

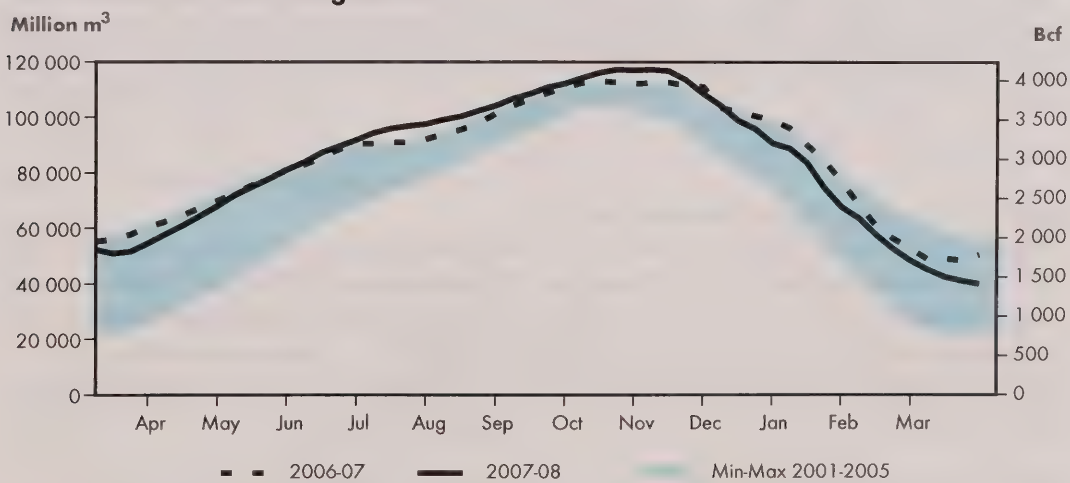
Natural gas prices can be sensitive to crude oil prices. Some consumers can switch between natural gas and fuel oil for their heating needs, particularly in the U.S. northeast and southeast. This competition provides a link, albeit imperfect, between oil prices and natural gas prices, such that an increase in crude oil prices can support an increase in the price of natural gas. Natural gas prices in North America, as measured by the 3-day average at the Henry Hub, shows that 2007 prices were about five percent lower than the 2006 average and less volatile.

Natural gas is produced at a steady rate throughout the year whereas its consumption is seasonal. To balance supply with demand, gas is injected into underground storage in the summer and withdrawn in the winter months. April is the beginning of the typical storage injection season (Figure 5.2). Above-normal temperatures in the winter of 2006-2007 left large volumes of natural gas in North American gas storage facilities at the beginning of April, about seven percent below the record-breaking April 2006 levels. Gas prices weakened through the spring and summer as large volumes of LNG were imported in to the US. By September, LNG imports receded by about half of the summer rate, as European and Asian LNG pre-winter demand increased. Natural gas storage in North America, particularly in the U.S., exceeded the 2006 levels by the end of October, to reach a new record high before entering the 2007-2008 winter heating season in November. Despite the high storage levels and mild early winter temperatures, natural gas prices rose from the late-September low.

Canadian natural gas prices, measured at the AECO hub in Alberta, began 2007 at $6.04/GJ and reached a low of $4.11/GJ in late August before closing the year at $6.12/GJ, following the trend of the U.S. Henry Hub price (Figure 5.3). Prices in eastern Canadian markets are cited at the Dawn hub, which is located near underground storage facilities in southwestern Ontario, and include a component of transportation and storage costs (see Figure 5.4).[4] The Dawn price began the year at US$5.94/MMBtu and reached a low of US$5.46/MMBtu in early September. The Dawn price rose gradually through autumn and early winter to close the year at US$7.62/MMBtu.

FIGURE 5.2

North American Gas Storage Levels

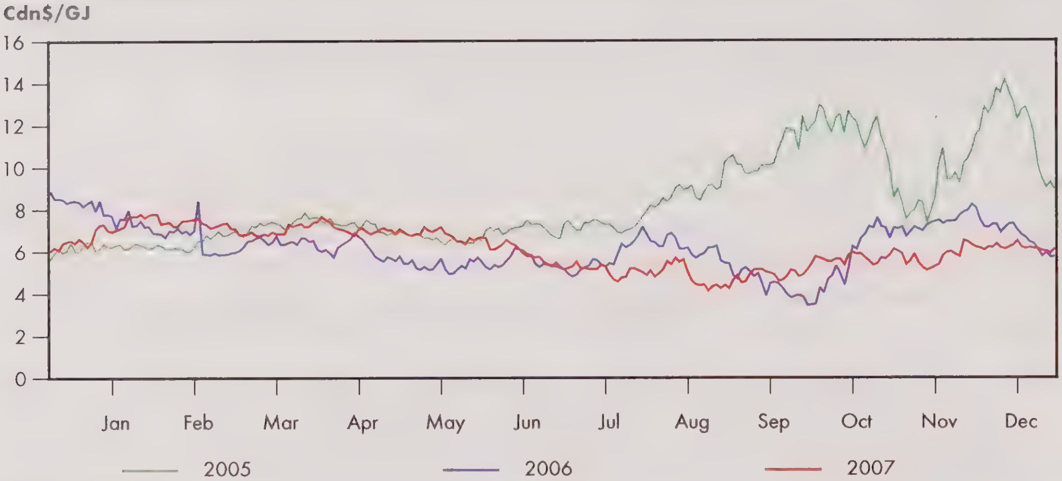


Source: Canadian Enerdata Ltd., NEB estimates, U.S. Energy Information Administration

4 Dawn trades are in US$/MMBtu

FIGURE 5.3

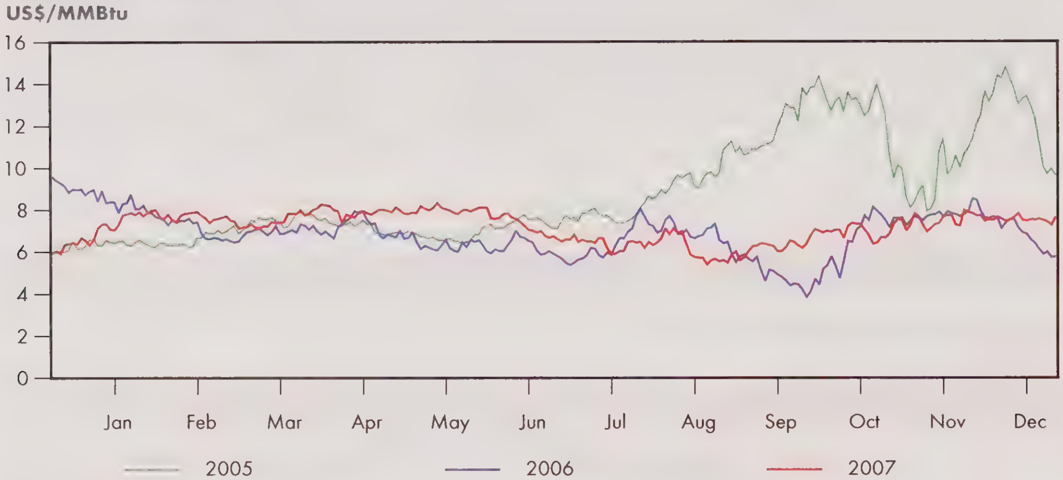
Daily AECO-C Price



Source: Platts

FIGURE 5.4

Daily Dawn Price



Source: Platts

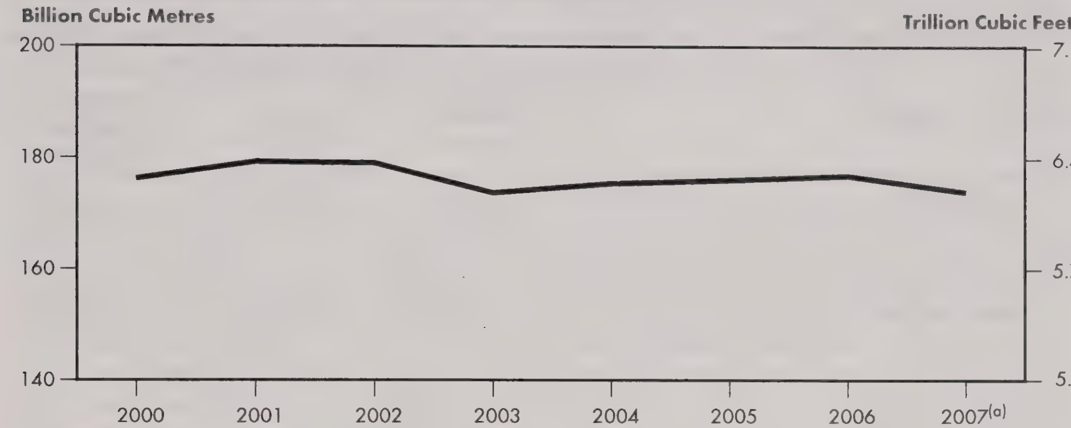
5.2 Natural Gas Production

Canadian natural gas production in 2007 averaged 476.5 million m^3/d (16.8 Bcf/d). This is roughly two percent less than in 2006. Western Canadian production remained relatively stable through the first half of the year as wells drilled during the first half of 2006 were connected into the pipeline system and brought on stream. The impact of reduced drilling was felt in the second half of the year with production slipping by an average of about 12.7 million m^3/d (0.4 Bcf/d).

On the East Coast, Sable production ramped up in the first half of the year as operation of the new compression facility became more consistent. In the second half, production stabilized at around 11.5 million m^3/d (0.41 Bcf/d) or about 33 percent higher than at the start of 2007. Additional production from the onshore McCully field in New Brunswick commenced midway through the year and gradually increased to represent about seven percent of the region's production.

FIGURE 5.5

Canadian Marketable Gas Production, 2000 - 2007



(a) Estimate

Development of the Deep Panuke gas project was initiated in 2007 following regulatory approval and a commercial decision to proceed. The earliest that gas production might occur is in 2010.

U.S. onshore production continued to increase in 2007 mainly through additional unconventional gas from Texas, Oklahoma, Arkansas and Rockies regions. Near the end of the year, a major deep water gas project in the Gulf of Mexico also began production. For the second consecutive year, there was no hurricane damage to U.S. production facilities in the Gulf of Mexico. As a result, average U.S. dry gas production for 2007 is estimated at 1 496 million m^3/d (52.8 Bcf/d) or roughly 62 million m^3/d (2.2 Bcf/d) higher than in 2006.

The U.S. has LNG import capacity of over 158.6 million m^3/d (5.6 Bcf/d) through six LNG terminals. In 2007, average LNG imports were 59.5 million m^3/d (2.1 Bcf/d), well above the 45.3 million m^3/d (1.6 Bcf/d) imported in 2005. LNG imports into the U.S. increased by an average 29.4 million m^3/d (1.0 Bcf/d) from March through August of 2007. The increase was aided by a mild winter leaving European gas storage relatively full and encouraging the diversion of cargoes to the U.S. LNG imports fell back after August as LNG demand increased in Japan to compensate for reduced nuclear output.

5.3 Natural Gas Reserves

The NEB's estimate of remaining marketable gas reserves at the end of 2006 (the last year for which data is available), is 1 647 billion cubic metres (58.1 trillion cubic feet) (Table 5.1). Reserve additions were 198 billion cubic metres (7.0 trillion cubic feet) in 2006 and replaced 116 percent of annual production. The rise in remaining reserves reflected exploration and improved recovery in known gas fields. Initial reserves increased in Alberta, British Columbia, Saskatchewan and Ontario in 2006 while frontier regions remained unchanged.

5.4 Canadian Natural Gas Consumption

Approximately one quarter of all energy consumed in Canada is natural gas with estimated consumption in 2007 of about 226 million m^3/d (7.97 Bcf/d), or about 47 percent of Canadian production. Natural gas is primarily consumed in the residential and commercial sectors for space heating, in the industrial sector for process heat, as a building block in chemical production, and

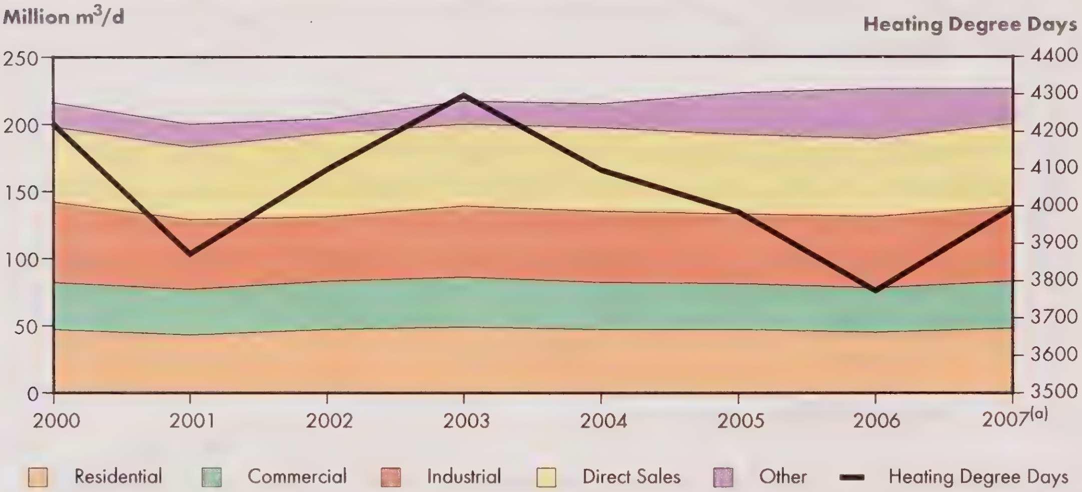
TABLE 5.1

Canadian Natural Gas Reserves, Year-end 2006 (10^9m^3)

(10^9m^3) At Year-end 2006	Natural Gas Reserves		
	Initial Reserves	**Cumulative Production**	**Remaining Established Reserves**
British Columbia	899.2	519.1	380.1
Alberta	4798.7	3 683.5	1 115.2
Saskatchewan	268.3	175.3	93.0
Subtotal - WCSB	**5 966.2**	**4 377.9**	**1 588.3**
Ontario	54.2	34.2	20.0
Nova Scotia Offshore	55.0	30.1	24.9
Mainland NWT & Yukon	29.3	16.2	13.1
Mackenzie Delta	0.3	0.1	0.2
Subtotal - Frontier	**84.6**	**46.4**	**38.2**
Total Canada	**6 105.0**	**4 458.5**	**1 646.5**
Total Canada (trillion cubic feet)	**215.5**	**157.4**	**58.1**

FIGURE 5.6

Canadian Total Gas Consumption and Heating Degree Days



(a) Estimate

Source: Statistics Canada, NEB Estimates and Canadian Gas Association

to produce electricity. Figure 5.6 also shows that Canadian gas demand for heating, industrial use and electric power generation (included within "direct sales") has been fairly flat since 2000. Larger amounts of natural gas have been seen, in recent years, in the "other" category that includes line pack fluctuation[5], gas used in the natural gas pipeline system, and lost and unaccounted volumes.

Despite continuing growth in residential and commercial floor space, actual natural gas consumption in this sector has changed little since 2000, and this is attributed, at least in part, to mild winter

5 Line pack is the volume of gas contained within a pipeline system at any point in time.

weather. Four of the past seven years rank among Canada's top 10 warmest years.[6] 2006 was the second warmest on record; based on preliminary data, 2007 ranks as the thirteenth warmest year, since nationwide records began in 1948. Besides weather effects, higher and more volatile natural gas prices have moderated natural gas consumption, particularly in the price-sensitive industrial sectors. In addition, the appreciating Canadian dollar over the past five years, has also adversely affected the Canadian manufacturing sector, which may result in lower manufacturing activity and consequently, lower natural gas consumption.

A fast growing sector for natural gas consumption is the Alberta oil sands. Figure 5.7 shows the natural gas consumption for oil sands operations from 2000 to 2007. Natural gas is used in both the generation of electricity and steam. Steam is used for in situ oil production and in the production of hydrogen to upgrade bitumen into synthetic crude oil blends. Consumption of natural gas in 2007 was almost 32 million m³/d (1.13 Bcf/d) - over three times the amount of gas used in 2000. Although, the oil sands industry is a large natural gas user, efforts are under way to reduce its dependence on this fuel. This includes pursuing energy efficiency improvements as well as the adoption of alternative fuels and technologies, such as bitumen gasification, which will provide the bulk of fuel requirements and feedstock in the OPTI/Nexen Long Lake SAGD/Upgrader project, which began production operations in late 2007.

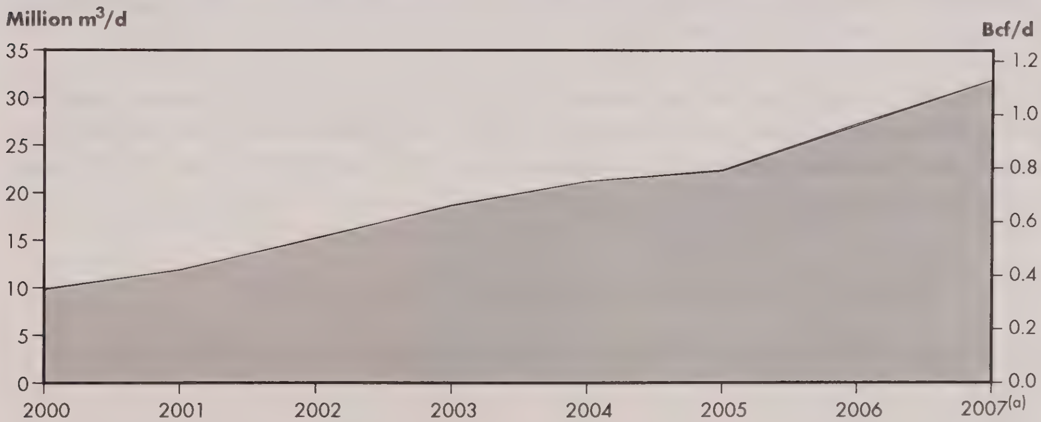
In the longer-term, it is expected that the application of bitumen gasification will gradually gain momentum in both in situ and upgrading operations. As well, the application of other technologies such as toe-to-heel air injection (THAI™) and Multiphase Superfine Atomized Residue (MSAR) will begin to play a role. Therefore, although natural gas demand in oil sands applications is expected to increase, it does not increase at the same rate as oil sands production.

5.5 Canadian Natural Gas Exports and Imports

Natural gas exports for 2007 were 294 million m³/d (10.4 Bcf/d) or about 17 percent of estimated U.S. consumption. The U.S. Central/Midwest and Pacific Northwest regions are Canada's largest export markets, with some volumes exported to the U.S. northeast. Overall, exports of natural gas

FIGURE 5.7

Average Annual Natural Gas Requirements for Oil Sands Operations



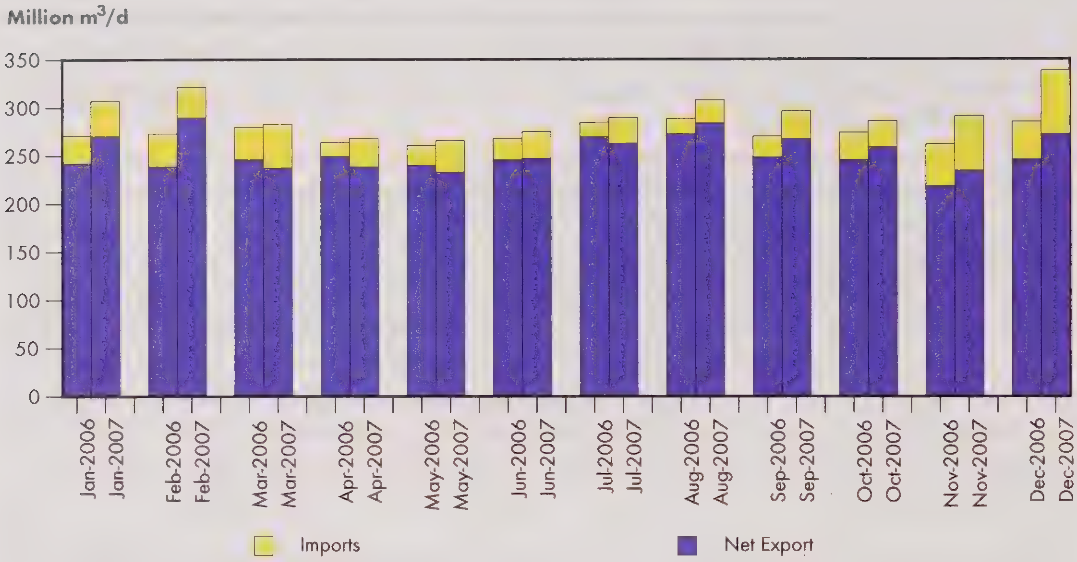
(a) Estimate

Source: NEB and Alberta Energy Resources Conservation Board

6 Environment Canada, Climate Trends and Variations Bulletin, Annual 2007, 28 January 2008. http://www.msc-smc.ec.gc.ca/ccrm/bulletin/national_e.cfm

FIGURE 5.8

Monthly Export and Import Volumes



Source: NEB

to the U.S. were higher in 2007 than 2006 (Figure 5.8). The extremely warm weather conditions of 2006 resulted in lower natural gas consumption and consequently, lower U.S. imports of Canadian gas. Therefore, the relatively cooler 2007 temperatures saw gas exports to the U.S. increase over 2006 levels.

The gross volume of Canadian gas exported to the U.S. was up 7.5 percent in 2007 compared with the previous year. Net exports (gross exports less imports) for 2007 were 258 million m^3/d (9.1 Bcf/d), about 4.4 percent higher than the 2006 net export volume of 247 million m^3/d (8.7 Bcf/d). Reduced Canadian gas drilling did not start to see the impact of lower Canadian gas production until the last quarter of 2007. Above-average storage inventories throughout 2007 also helped meet natural gas consumption in Canada as exports increased and natural gas production declined.

Overall, Canadian revenues from gas exports in 2007 were very similar to 2006. Although there was an increase in export volumes, the average export price was about five percent lower in 2007 than in 2006 resulting in net export revenues of $24.3 billion, almost the same as net export revenues in 2006.

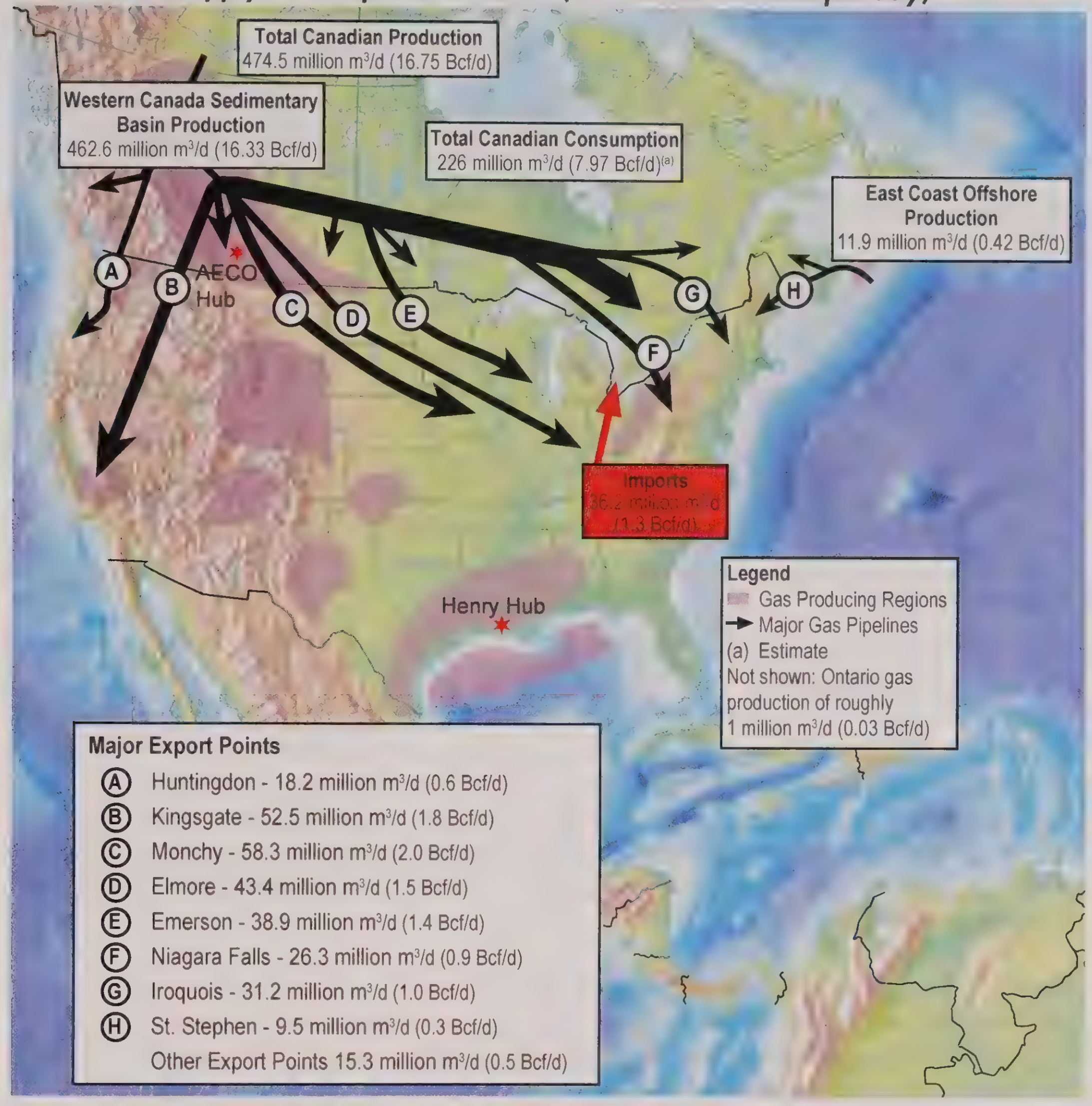
Canada is a net exporter of natural gas; however, 36.2 million m^3/d (1.3 Bcf/d) of gas was imported into Ontario from the U.S. in 2007 (Figure 5.9). Pipeline infrastructure allows gas to flow along a choice of pipeline options when destined to eastern markets. As a result, Ontario may import natural gas if it is economic.

5.6 Natural Gas Liquids (excluding Pentanes Plus)

Natural gas liquids (NGLs) refer to the liquid hydrocarbon products extracted from the natural gas stream and are initially recovered as a hydrocarbon mix. The component parts can then be further separated into marketable products such as ethane, propane and butanes. Propane and butanes are also produced from crude oil refining and upgrading processes. Products from these processes are sometimes referred to as liquefied petroleum gases (LPG). In 2007, it is estimated that 88 percent of propane and 67 percent of butane supplies came from natural gas production.

FIGURE 5.9

Natural Gas Supply and Disposition – 2007 (million cubic metres per day)



Propane prices remained high throughout 2007 driven largely by rising crude oil prices and strong feedstock demand in the petrochemical sector in North America. The high price, however, did not result in higher production levels for propane. In 2007, propane production from gas plants decreased by about five percent to 26 600 m³/d (168 Mb/d). This decrease can be attributed to lower drilling rates for natural gas because of depressed natural gas prices and higher drilling costs. Ethane and butane production from gas plants decreased slightly to 42 250 m³/d (266 Mb/d) and 15 400 m³/d (97 Mb/d), respectively.

In 2007, refinery production for both propane and butane increased from 2006 levels due to higher conventional crude oil production and the return from maintenance of upgraders at oil sands mining operations. Refinery production of propane is estimated at 3 800 m³/d (24 Mb/d), a six percent increase. Refinery butane production increased by four percent to meet strong Canadian domestic demand for butane as a heavy oil diluent.

The U.S. Midwest continues to be Canada's largest market for propane and butanes, accounting for about 60 percent and 45 percent, respectively, of the total export volumes of NGLs. Estimated 2007

propane exports declined by seven percent to 17 500 m^3/d (110 Mb/d) and butane exports decreased by 13 percent to 3 800 m^3/d (24 Mb/d). The decrease in propane exports was mainly due to lower heating demand caused by mild weather during most of the winter season in North America; whereas, the lower butanes export volume was caused by strong diluent demand in the Alberta heavy oil sector.

Despite lower propane export volumes in 2007, propane prices were slightly higher and this resulted in the estimated export revenue increasing by three percent to $2.1 billion. Butane prices were also marginally higher in 2007; however, export volumes were lower resulting in a decline of six percent to $555 million. Export revenue for the two commodities combined, totalled almost $2.7 billion.

5.7 Looking Ahead

In the coming years, it is expected that North American demand for natural gas will continue to outpace the growth in domestic supplies. In Canada, natural gas supply from new sources such as frontier regions, LNG, coalbed methane (CBM) and shale gas will be increasingly required to supplement declining supply from the conventional sources of the WCSB and Sable Island to meet growing demand. Significant incremental requirements for natural gas in Canada will come from growing gas consumption in oil sands developments in Alberta and new gas-fired electrical generation in Ontario which will help displace existing coal-fired electricity generation and meet growing electricity demand.

Liquefied Natural Gas

To meet the growing North American demand for natural gas, it is expected that natural gas from the global LNG market will become an increasingly important component of North America supply. Proven reserves of natural gas worldwide are about 20 times larger than the proven natural gas reserves of North America. Continued development of liquefaction capacity in producing regions and growth in the global LNG shipping fleet will enable North American markets to access greater LNG supply in the world market.

In anticipation of growing natural gas requirements in North America, there are numerous proposals to expand existing U.S. terminals and construct new LNG receiving facilities in North America, including several proposed projects in Canada as summarized in Figure 5.10. However, there is uncertainty around the number of LNG terminals that may eventually be built in Canada. The experience in the U.S. is that these terminals do not operate at full capacity but rather the amount of LNG received is dependent on the relative price of North American gas markets. The Canaport LNG facility in Saint John, New Brunswick is currently under construction and its scheduled in-service date is late 2008.

These potential changes in Canada's natural gas supply and demand have important implications to both existing pipeline transportation systems and proposed new pipeline and LNG projects. Facilities that connect significant new gas supply from new sources such as the North and LNG or significant changes in regional demand (e.g., oil sands in Alberta and electricity generation in Ontario) will have the potential to influence markets and alter the utilization and gas flow on existing pipelines. In turn, these changes may impact the tolls and associated costs in using those pipelines. For example, the introduction of new gas supply in eastern Canada could result in greater utilization or flow reversals in regional pipelines and may also affect the flow of supply from traditional sources and pipelines. Similarly, greater demand in Alberta or Ontario can alter the flow and availability of natural gas to adjacent regions.

FIGURE 5.10

Proposed Canadian LNG Projects (Bcf/d)

Location	Terminal	Proponent(s)	Capacity	Proponents' Estimated On-Stream Date
1. Placentia Bay, Newfoundland	Grassy Point LNG	Newfoundland LNG Ltd.	LNG Storage & Trans-shipment	2010
2. Point Tupper, Nova Scotia	Statia LNG	Statia Terminals Canada Partnership	0.5	n/a
3. Goldboro, Nova Scotia	Maple LNG	4Gas and Suntera Canada Ltd.	1.0	2010
4. Saint John, New Brunswick	Canaport LNG	Repsol YPF and Irving Oil	0.8	2008
5. Rivière-du-Loup, Quebec	Gros Cacouna LNG	Petro-Canada and TransCanada Pipelines Ltd.	0.5	2012
6. Québec City, Quebec	Rabaska	Gaz Métro, Enbridge and Gaz de France	0.5	2011
7. Saguenay, Quebec	Énergie Grande-Anse	Saguenay Port Authority and Énergie Grande-Anse Inc.	1.0	2012
8. Bish Cove, British Columbia	Kitimat LNG	Galveston LNG	1.0	2010/11
9. Texada Island, British Columbia	Texada Island LNG	WestPac LNG Corporation	0.5	n/a

The expected introduction of LNG close to Canadian markets has also heightened the awareness of end-users and distributors to the potential issues related to gas composition and quality. Consequently, pipelines will need to work closely with their customers to establish gas quality standards and monitor processes to ensure compatibility with existing equipment and end-use operation.

ELECTRICITY

6.1 Market Development Initiatives

Growth in the electricity industry continued as regional jurisdictions made efforts to maintain adequate supply and reliable operation. Initiatives implemented over 2007 included conservation measures, clean energy programs and infrastructure additions. Governments also continued to play a role in the development of the electricity industry.

A number of jurisdictions introduced plans for conservation initiatives as a means of managing their supply and demand balance. In February 2007, the Government of British Columbia released its energy plan, *A Vision for Clean Energy*, which includes conservation targets for the province. Additionally, in late August, the Ontario Power Authority (OPA) filed an application for approval of its *Integrated Power System Plan*, a 20-year plan for the province's electricity system that includes electricity conservation measures. Ontario revealed evidence that its electricity demand growth was moderating, a result attributed to conservation initiatives already implemented.

In 2007, Hydro-Québec launched construction at Eastmain-1-A/Sarcelle/Rupert, in the James Bay region. This project would add 8.5 terrawatt hours to Quebec's annual hydroelectric output. In September, the fifth and final generating unit at Mercier, in the Outaouais region, went into operation. Concurrently, Hydro-Québec stepped up work at the Outaouais substation, a cornerstone of the new, 1 250 megawatt interconnection with Ontario that got off the ground in late 2006.

The contribution of wind power to the resource plan was enhanced in 2007 with the commissioning of the 100.5 megawatt L'Anse-à-Valleau facility in November. This is the second of eight wind farms slated for construction in the Gaspé region by the end of 2012. These agreements signed with private companies will add 990 megawatts of wind power. In September, following the closing of the 2005 tender call for an additional 2 000 megawatts, Hydro-Québec received 66 bids from 30 proponents for a total of 7 724 megawatts.

An interesting development in Quebec in 2007 resulted from an oversupply of electricity in the province. The rapid increase in wind and hydroelectric developments in recent years combined with an economic slowdown has led to a temporary oversupply of electricity. To deal with this situation, Hydro-Québec has agreed to pay TransCanada to stop production of electricity at their Becancour plant.

The environment continued to be at the forefront of government policy actions. Clean energy programs that are designed to reduce greenhouse gas emissions were introduced at both federal and provincial levels. The Federal Government announced in January 2007 that it would invest $230 million over four years to develop clean energy technologies. The plan, called the *ecoEnergy Technology Initiative*, will fund research for technologies involved in clean-coal, carbon sequestration, reducing oil sands' environmental impact, new end-use technologies such as hydrogen and fuel cells,

and energy efficient buildings and industry. The initiative will also develop technologies for producing and using renewable energy from clean sources, such as wind, solar, tidal and biomass. It will focus on advancing research in these areas and will fund demonstrations through public–private partnerships, although the details of the plan are not yet available. As well, British Columbia's new energy plan, for example, calls for all new and existing electricity generation to be net zero greenhouse gas emissions by 2016 and has eliminated any plans for coal-fired generation. Additionally, clean or renewable electricity generation will account for at least 90 percent of total generation.

An ongoing requirement across the country is the need for new or upgraded transmission. A number of transmission plans and projects were proposed in 2007. In addition to Ontario's periodic review of its Integrated Power System Plan, British Columbia and Alberta announced 10-year transmission system plans. The focus of British Columbia's plan is to maintain the reliable performance of its existing infrastructure and build new capacity to meet customer demand. Alberta's plan is intended to help the province keep up with forecasted demand and economic growth by addressing both demand growth and generation development needs. In September 2007, Newfoundland and Labrador released their first energy plan titled *Focusing our Energy*. The 35-year energy plan is designed to help the province achieve self-reliance and prosperity and to help develop sustainable green energy solutions.

With the need for new and improved generation and transmission facilities across Canada, common challenges in the approval process have arisen. One such challenge is the increased sensitivity toward obtaining public acceptance of these projects. Public acceptance is increasingly important in the management of the project approval process.

Government regulation of the electricity industry continues to evolve. For example, under Special Direction 9, the British Columbia Utilities Commission may now approve projects that anticipate demand for electricity service over a period of time. This will enable the British Columbia Transmission Corporation to investigate a new system expansion plan to prevent transmission congestion before it occurs. Also, in June 2007, the Government of Alberta announced that it would separate the Alberta Energy and Utilities Board (EUB) into two entities - the Energy Resources Conservation Board (ERCB) and the Alberta Utilities Commission (AUC), effective 1 January 2008. The new legislation was designed to promote efficiency in Alberta's regulatory system.

Electricity prices increased in a number of Canadian jurisdictions in 2007 because of the cumulative effects of higher fuel costs in recent years and higher costs for new generation and transmission investments. Figure 6.1 provides a cross-country perspective on residential electricity prices in 2006 and 2007 for representative cities in each province. Predominantly hydroelectric-generating provinces (B.C., Manitoba and Quebec) tend to have lower electricity prices while jurisdictions with gas-fired and oil-fired generation tend to have higher prices.

6.2 Electric Reliability

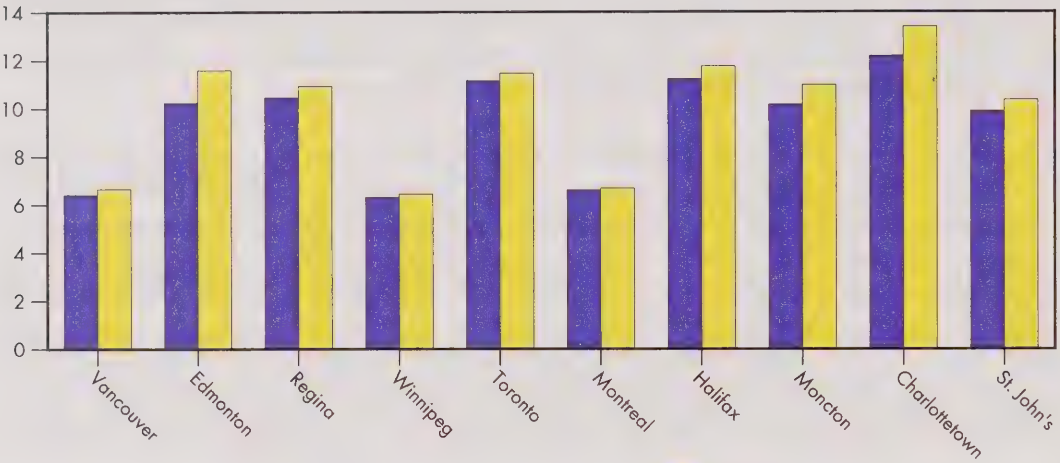
There are two main aspects to reliability: adequacy of supply achieved through sufficient generation and transmission capacity; and, operating reliability, achieved through operating and maintaining the bulk power system elements so as to withstand disturbances or contingencies and continue operations. In Canada, the reliability of the bulk transmission systems continues to be a focus of the electric industry, regulators and policy makers.

In August 2007, following up on a recommendation made by the Canada–U.S. task force, which examined the causes of the August 2003 power outage in Ontario and the U.S. Northeast, the Board published a report entitled *Reporting of Electric Reliability Information by Canadian Entities*. The

FIGURE 6.1

Canadian Residential Electricity Prices

Cents (Cdn) per kW.h



Source: Hydro-Québec: Comparison of Electricity Prices in Major North American Cities, 2006 and 2007

report concluded that compiling reliability performance information to enable an assessment of reliability trends would be useful to industry, regulators, policy makers and the public. The report also concluded that the North American Electric Reliability Corporation (NERC) was making efforts directed toward compiling this information and therefore, the need for another entity to provide an independent source of reliability information in Canada is not justified at this time.

Cross-border jurisdictions continued to express interest in new interconnections. In February 2007, the Province of New Brunswick and State of Maine signed an MOU that outlined a timeframe for researching and creating actions that will enhance cross-border interconnections. In recent years there have been discussions of an east–west Canadian power grid at the provincial and federal levels. The most recent support for this initiative occurred in August 2007 when the country's premiers encouraged the concept of a national transmission grid to ensure Canadians benefit fully from the country's energy resources. Although no commitment was made, support for enhanced transmission facilities was evident.

In spring 2007, the Board issued a permit to Montana Alberta Tie Ltd. to construct and operate the Canadian portion of an international power line between Lethbridge, Alberta and Great Falls, Montana. The planned 230 kilovolt line is expected to be 347 kilometres long, of which, 130 kilometres will be in Canada. This is the second merchant line the Board has approved, the first being Seabreeze in September 2006, and will be the first major interconnection between Alberta and the U.S. Additionally, the 345 kilovolt international power line extending from Point Lepreau generating station in New Brunswick to a point near Woodland, Maine was energized in December 2007. The Board had approved the application for this line in May 2003.

Regional infrastructure projects continued to move forward in 2007 as jurisdictions worked to maintain and improve the reliability of their systems. One such project that addresses cross-border relationships is the 1 250 megawatt interprovincial transmission line between Ontario and Quebec. Hydro-Québec Équipement began construction of the line's Outaouais converter station in the municipality of L'Ange-Gardien in mid 2007. The new facilities would increase the energy

interchange between Quebec and Ontario to nearly 3 000 megawatts. In addition to supplying Ontario with renewable energy, the interconnection would improve the reliability of transmission for serving Quebec loads. This first phase of the proposed line is expected to be completed in 2009.

The Alberta government and the Alberta Electric System Operator (AESO) removed a 900 megawatt wind threshold in September 2007. The threshold, introduced in May 2006, had been introduced in an effort to address potential operational reliability concerns associated with integrating wind generation into the Alberta electric system, thereby avoiding additional stress on the transmission system. The system operator now believes that recent and near-term enhancements to the southern Alberta grid will enable it to manage wind-associated issues, and thus removed the cap which was seen as delaying the growth of this green power source. At the end of 2007, Alberta had over 520 megawatts of wind generation capacity, an increase from 384 megawatts in 2006.

In September 2007, the planned 500 kV Edmonton–Calgary transmission line proceedings were cancelled by the EUB and applications to construct and operate the line put on hold. The transmission line was intended to strengthen the Alberta grid by alleviating system constraints and improving system efficiency by providing southern load centres access to generation in the north of the province. Including this project, Alberta's 10-year transmission plan estimates $1.5 billion in investments to address its foreseen supply and reliability issues.

6.3 Electricity Generation

Generation needs continued to be addressed across Canada through province-by-province planning. Alternative forms of generation (e.g., wind generation, small hydro, biomass) are being proposed. Additionally, there has been a resurgence of interest in nuclear generation, which, along with other conventional generation types (e.g., natural gas-fired generation and hydrogeneration) dominate the generation mix. The environment and environmentally favourable types of generation continue to be taken into account when jurisdictions plan for future needs.

Wind generation capacity increased to 1 770 megawatts, an increase of more than 300 megawatts from 2006, which, according to the Canadian Wind Energy Association, is enough energy to power 537 000 homes. Nuclear generation is attractive for its low, or no, emissions and potential large addition to generation capacity. In 2007, Energy Alberta proposed to build a nuclear generator in north-central Alberta. An application was filed with the Canadian Nuclear Safety Commission (CNSC) in August. The plant would generate 2 200 megawatts of electricity and could come online in 2017. Subsequently, on 13 March 2008, Bruce Power Alberta announced its purchase of Energy Alberta's assets related to the nuclear plant development. On the same day, Bruce Power filed an application with CNSC to prepare the site for a nuclear plant which could generate 4 000 megawatts of electricity. Additionally, Ontario continues to reassess its nuclear program and New Brunswick is investigating the option of adding a second nuclear reactor at its Point Lepreau site.

Another large generation project, which began construction in January 2007, was Quebec's Eastmain-1-A, a $5.0 billion dollar hydroelectric project. The 900 megawatt dam, the first major project in over a decade for the province, is located in northern Quebec and is expected to come online in 2009. Also, Manitoba Hydro and the Nisichawayasihk Cree Nation formally entered into a joint venture to build the 200 megawatt Wuskwatim Generating Station. The $1.3 billion dollar hydroelectric-generation facility is scheduled for completion in 2012.

In Ontario, two large combined-cycle gas-fired power plants are scheduled to come online. The Greenfield Energy Centre will provide 1 005 megawatts of capacity and is scheduled for commercial

operations early in 2008, and the St. Clair Energy Centre will provide 570 megawatts of capacity and is scheduled for commercial operations in early 2009.

SaskPower cancelled plans for construction of a 300 megawatts clean coal project because of uncertainties regarding cost and timing. Instead they opted for more conventional and cheaper natural gas-fired generation, wind power and renewables to meet the province's electricity needs to 2014. However, the feasibility work on the 300 megawatts facility has provided confidence that the technology can succeed in Saskatchewan. In early 2008, an industry-SaskPower partnership received federal funding in support of a smaller, 100 megawatts clean coal demonstration project. This project is expected to be fully operational in 2015.

Total Canadian electricity generation increased from 585 terawatt hours in 2006 to 600 terawatt hours in 2007 (Table 6.1). Hydro electric generation increased from 351 terawatt hours in 2006 to 362 terawatt hours in 2007. The increase can be attributed to favourable water conditions in hydroelectric-generating provinces. Thermal generation increased from 142 terawatt hours in 2006 to 150 terawatt hours in 2007. Lower natural gas prices that supported increased thermal generation can be attributed, in part, to the change. Nuclear generation decreased from 92 terawatt hours in 2006 to 88 terawatt hours in 2007 largely because of a number of plant outages over the year.

6.4 Electricity Demand

In 2007, Canadian electricity demand was adequately met from domestic generation and imports. However, unexpected challenges, such as extreme weather events, system failures and unplanned outages can impact reliability and the supply/demand balance.

One such unplanned event resulted in southern Saskatchewan being without electricity for several hours on the morning of 18 September 2007. The exact cause of the blackout is still unknown but it is believed to have been caused by a storm that tripped several transmission lines in Minnesota. A task force, that includes 25 organizations, is being coordinated by the North American Electric Reliability Corporation to discover the exact cause.

Short-term supply/demand tightness was experienced in two Canadian jurisdictions during summer 2007. In Ontario, the Independent Electricity System Operator (IESO) issued an appeal for energy conservation at the end of June and beginning of August 2007. Hot weather was a factor in both alerts. In Alberta, the Alberta Electric System Operator issued five separate alerts as the system reached four new summer demand peaks in July 2007, the final peak demand being 9 321 megawatts. Normal summer consumption is usually in the range of 8 000 to 8 500 megawatts. Hot weather was a factor in the alerts in addition to a large, annual increase in demand.

TABLE 6.1

Electricity Production[a]
(terawatt hours)

	2003	2004	2005	2006	2007[b]
Hydroelectric	332.9	335.1	358.6	351.1	361.8
Nuclear	70.7	85.3	86.8	92.4	87.9
Thermal	160.7	150.9	151.8	141.6	150.1
Total	**564.2**	**571.3**	**597.2**	**585.1**	**599.7**

(a) Source: Statistics Canada Energy Statistics Handbook. Table 8.2 Utility Generation of Electricity in Canada and Table 8.3 Industry Generation of Electricity in Canada

(b) Estimates

6.5 Electricity Exports and Imports

Canadian electricity jurisdictions tend to be winter-peaking systems and so the largest imports of electricity from the United States typically occur during the winter when local heating requirements are highest.

Exports increased 23 percent from 40.8 terawatt hours in 2006 to 50.1 terawatt hours in 2007 and were 37 percent above the five year average of 36.5 terawatt hours. Imports decreased from 23.4 terawatt hours in 2006 to 19.6 terawatt hours in 2007. In 2007, imports were about six percent below the five year average of 20.8 terawatt hours. Canada exported approximately \$3.1 billion of electricity in 2007 compared to \$2.4 billion in 2006, an increase of 28 percent. Import revenues for 2007 totalled \$1.0 billion, down from \$1.2 billion the previous year, or a nine percent decrease.

Net exports increased by 76 percent from 17.4 terawatt hours in 2006 to 30.6 terawatt hours in 2007. In 2007, net exports were nearly double the five-year average of 15.7 terawatt hours. Figure 6.2 illustrates international and interprovincial transfers of electricity.

The overall increase in exports and export revenues can be attributed to favourable water conditions in hydroelectric-generating provinces that allowed for strong exports and enabled the provinces to capitalize on higher electricity prices in the U.S. The good water conditions also allowed the provinces to reduce their need for electricity imports.

6.6 Looking Ahead

The path followed in recent years by provincial jurisdictions in planning for adequate and reliable supplies of electricity is expected to continue. This includes the coming to fruition of many of the supply side initiatives already begun and the impact of conservation and improved efficiency should become evident in at least some provinces.

FIGURE 6.2

International and Interprovincial Transfers of Electricity[a] (GW.h)

Exports and imports are expected to continue to be a significant source of revenue and provide reliability for those provinces interconnected with adjacent U.S. regions. Export revenues will continue to be dominated by hydroelectric-generation provinces. Jurisdictions are expected to continue initiatives toward improving interconnections both interprovincially and internationally.

Electricity rates will continue to be affected by fuel prices, changes in operating costs and the impact of adding new infrastructure. Short-term price fluctuations in competitive wholesale markets will be influenced by weather and the occurrence of temporary tight supply situations. The specific impact on final consumers (residential, commercial and industrial) will depend on the electricity rate decisions of the provincial regulators and the extent to which provincial markets have deregulated electricity prices. Alberta and Ontario remain the jurisdictions furthest along in implementing market prices.

Conclusion

Canada is endowed with an abundance of natural energy resources. This abundance is a source of national pride and provides Canadians with a range of energy choices. Ensuring that Canadians have timely and relevant energy information so they can make informed energy choices is part of the National Energy Board's strategic plan. One of the ways the Board achieves this objective is through this review of Canadian energy markets over the last year. In 2007, Canadian energy markets continued to function well and there were sufficient energy supplies available to meet the energy needs of Canadians.

Energy is essential to our daily lives. It is also an important economic driver, accounting for 5.6 percent of our GDP and almost 20 percent or $90 billion of the total value of Canadian exports. Net energy exports increased by almost eight percent in 2007 to $50.8 billion, led by increases in the value of oil and electricity exports. The energy industry also accounts for about 35 percent or $68.9 billion of total private sector investment. This contributes to the economic prosperity of our entire country and helps guarantee the high standard of living we enjoy.

2007 marked a year of rising and fluctuating energy prices and Canadians were not isolated from this phenomenon. While Canada is a net exporter of crude oil, natural gas and electricity, high energy costs can still be a burden for consumers and industry. The growing strength of the Canadian dollar compared to the U.S. dollar helped mitigate some of the impact of rising global energy prices on Canadian consumers. Despite higher energy costs, Canadian energy demand increased by 2.8 percent, reflecting strong population and economic growth, particularly in the first half of 2007.

Growing investment in Canadian natural resources, particularly the oil sands, have propelled Canada into a major role in the global energy market. The oil sands resource has attracted financial capital from multi-national companies looking to invest in a country with a stable government and sound economic policy. Canada is one of the few countries in the world with significant potential to increase its energy production, particularly oil output. Increased oil sands production and investment has led to strong economic growth in Alberta, contributed to provincial and federal government revenues, and provided spin-off opportunities in other provinces.

The National Energy Board's vision is to be an active, effective and knowledgeable partner in the responsible development of Canada's energy sector for the benefit of Canadians. Canadians will face challenges as we continue to learn to manage our energy resources in a more responsible way. Much remains to be done. Canadians, however, have the will, the resources and the know-how to make the changes that will move our society toward a sustainable future.

Glossary

Bitumen or crude bitumen	A highly viscous mixture, mainly hydrocarbons heavier than pentanes. In its natural state, it is not usually recoverable at a commercial rate through a well because it is too thick to flow.
Coalbed methane	Is a form of natural gas extracted from coalbeds. Coalbed methane, often referred to as CBM, is distinct from a typical sandstone or other conventional gas reservoir as the methane is stored within the coal by a process called adsorption.
Conventional crude oil	Crude oil, which at a particular point in time, can be technically and economically produced through a well using normal production practices and without altering the natural viscous state of the oil.
Conventional gas	Refers to natural gas from all sources other than CBM.
Deliverability	The amount of natural gas a well, reservoir, storage reservoir or producing system can supply at a given time.
Diluent	Any lighter hydrocarbon, usually pentanes plus, added to heavy crude oil or bitumen in order to facilitate its transport on crude oil pipelines.
Hub	A geographic location where large numbers of buyers and sellers trade a commodity and where physical receipts and deliveries occur.
In situ recovery	The process of recovering crude bitumen from oil sands other than by surface mining.
Line pack	The actual amount of gas in a pipeline or distribution system.
Marketable gas	Natural gas that has been processed to remove impurities and natural gas liquids. It is ready for market use.
Natural gas liquids	Those hydrocarbon components recovered from natural gas as liquids. These liquids include, but are not limited to, ethane, propane, butanes and pentanes plus.

Oil sands	Sand and other rock material that contains bitumen. Each particle of oil sand is coated with a layer of water and a thin film of bitumen.
Pentanes plus	A mixture mainly of pentanes and heavier hydrocarbons obtained from the processing of raw gas, condensate or crude oil.
Reserves – Established	The sum of the proven reserves and half probable reserves.
Reserves – Initial Established	Established reserves prior to deduction of any production.
Reserves – Proven	Reserves recoverable under current technology and present and anticipated economic conditions, specifically demonstrated by drilling, testing or production.
Reserves – Remaining	Initial reserves less cumulative production at a given time.


70

National Energy Board
Office national de l'énergie

Canadian Energy Overview 2008

AN ENERGY MARKET ASSESSMENT MAY 2009

Canada

National Energy Board

Office national de l'énergie

Canadian Energy Overview 2008

AN ENERGY MARKET ASSESSMENT MAY 2009

Canada

Permission to Reproduce

Materials may be reproduced for personal, educational and/or non-profit activities, in part or in whole and by any means, without charge or further permission from the National Energy Board, provided that due diligence is exercised in ensuring the accuracy of the information reproduced; that the National Energy Board is identified as the source institution; and that the reproduction is not represented as an official version of the information reproduced, nor as having been made in affiliation with, or with the endorsement of the National Energy Board.

For permission to reproduce the information in this publication for commercial redistribution, please e-mail: info@neb-one.gc.ca

Autorisation de reproduction

Le contenu de cette publication peut être reproduit à des fins personnelles, éducatives et(ou) sans but lucratif, en tout ou en partie et par quelque moyen que ce soit, sans frais et sans autre permission de l'Office national de l'énergie, pourvu qu'une diligence raisonnable soit exercée afin d'assurer l'exactitude de l'information reproduite, que l'Office national de l'énergie soit mentionné comme organisme source et que la reproduction ne soit présentée ni comme une version officielle ni comme une copie ayant été faite en collaboration avec l'Office national de l'énergie ou avec son consentement.

Pour obtenir l'autorisation de reproduire l'information contenue dans cette publication à des fins commerciales, faire parvenir un courriel à : info@neb-one.gc.ca

Cat. No. NE2-4/2008E
ISBN 978-1-100-12621-0

This report is published separately in both official languages. This publication is available upon request in multiple formats.

Copies are available on request from:
The Publications Office
National Energy Board
444 Seventh Avenue S.W.
Calgary, Alberta, T2P 0X8
E-mail: publications@neb-one.gc.ca
Fax: 403-292-5576
Phone: 403-299-3562
1-800-899-1265
Internet: www.neb-one.gc.ca

For pick up at the NEB office:
Library
Ground Floor

Printed in Canada

Nº de cat. NE2-4/2008F
ISBN 978-1-100-91554-8

Ce rapport est publié séparément dans les deux langues officielles. On peut obtenir cette publication sur supports multiples, sur demande.

Demandes d'exemplaires :
Bureau des publications
Office national de l'énergie
444, Septième Avenue S.-O.
Calgary (Alberta) T2P 0X8
Courriel : publications@neb-one.gc.ca
Télécopieur : 403-292-5576
Téléphone : 403-299-3562
1-800-899-1265
Internet : www.neb-one.gc.ca

Des exemplaires sont également disponibles à la bibliothèque de l'Office :
Rez-de-chaussée

Imprimé au Canada

TABLE OF CONTENTS

FIGURES

TABLES

BPS	Bulk Power System
CanWEA	Canadian Wind Energy Association
CBM	coalbed methane
CCS	carbon capture and storage
CH_4	methane
CMHC	Canada Mortgage and Housing Corporation
CO_2	carbon dioxide
ECAM	Energy Cost Adjustment Mechanism
EIA	Energy Information Administration
EMA	Energy Market Assessment
ERCB	Alberta Energy Resource Conservation Board
GDP	gross domestic product
GHG	greenhouse gas
H_2O	water vapor
HDD	heating degree days
HFC	hydrofluorocarbons
IEA	International Energy Agency
IPL	international power line
LMCI	Land Matters Consultation Initiative
LNG	liquefied natural gas
N_2O	nitrous oxide
NAFTA	North American Free Trade Agreement
NEB or Board	National Energy Board
NERC	North American Reliability Corporation
NGLs	natural gas liquids
NRCan	Natural Resources Canada
NRF	New Royalty Framework
NSB	North Sea Brent
O_3	ozone
OECD	Organization for Economic Co-operation and Development
OPEC	Organization for Petroleum Exporting Countries
PADD	Petroleum Administration for Defense District
PFC	perfluorocarbons
RPP	Regulated Price Plan
RRO	Regulated Rate Option
SAGD	Steam Assisted Gravity Drainage
SF_6	sulphur hexafluoride
THAI™	toe-to-heel air injection
U.S.	United States
WCI	Western Climate Initiative
WCSB	Western Canada Sedimentary Basin
WTI	West Texas Intermediate

LIST OF UNITS

$10^6m^3/d$	million cubic metres per day
b/d	Barrels per day
bbl	barrel
Bcf/d	Billion cubic feet per day
BTU	British thermal unit
BTU/ft^2	British thermal unit per square feet
Cdn$ or $	Canadian dollars
GJ	gigajoule
GW.h	Gigawatt hour
ha	hectare
kW.h	Kilowatt hours
m^3	cubic metres
m^3/d	cubic metres per day
Mb/d	thousand barrels per day
MMb/d	million barrels per day
MMbtu	million British thermal units
MMcf/d	Million cubic feet per day
Mt	megatonne
MW	megawatt
PJ	petajoules
US$	U.S. dollars
Tcf	Trillion cubic feet
TW.h	Terawatt hour

FOREWORD

The National Energy Board (NEB or the Board) is an independent federal agency that regulates several aspects of Canada's energy industry. Its purpose is to promote safety and security, environmental protection and efficient energy infrastructure and markets in the Canadian public interest within the mandate set by Parliament in the regulation of pipelines, energy development and trade. The Board's main responsibilities include regulating the construction and operation of interprovincial and international oil and gas pipelines as well as international and designated interprovincial power lines. The Board regulates pipeline tolls and tariffs for pipelines under its jurisdiction. The Board regulates the exports and imports of natural gas as well as exports of oil, natural gas liquids (NGLs) and electricity. The Board also regulates oil and gas exploration, development and production in frontier lands and offshore areas not covered by provincial or federal management agreements. The Board's advisory function requires it to keep under review matters over which Parliament has jurisdiction relating to all aspects of energy supply, transmission and demand for Canadian energy.

The NEB monitors energy markets to objectively analyze energy commodities and inform Canadians about trends, events and issues. Annually, the Board conducts a review of the previous year's energy markets in an Energy Market Assessment (EMA), entitled *Canadian Energy Overview*. This year's report, *Canadian Energy Overview 2008* is a summary of major developments related to energy in Canada in 2008.

Executive Summary

The year 2008 was exceptional in global energy markets. Rising energy prices, growing concerns and increasing political momentum about climate change, and heightened public interest in energy and environmental issues characterized the first half of the year. Decreased demand and significantly reduced prices, the financial and credit crisis, and a realization that the industrialized economies were plunging into a recession shifted public focus to economic concerns in the second half. Canada and the world saw highly volatile crude oil and natural gas prices, which created uncertainty and made it difficult for industry, consumers and government to prioritize investments. Superimposed over the price volatility was a weakened global banking sector that resulted in a credit environment in which access to necessary capital for spending was extremely difficult.

Canada has a responsibility to promote and encourage sustainable energy development and practices that benefit all Canadians. Energy, the environment, and the economy are becoming increasingly interconnected. Numerous federal and provincial policies aimed at sustainable development and reducing the consumption of energy were advanced in early 2008. The federal government released more details on its *Regulatory Framework for Greenhouse Gas Emissions* and provincial governments introduced legislation setting firm targets for the reduction of greenhouse gases (GHGs). The focus both federally and provincially reflects a North American push to reduce fuel consumption.

Energy remained a vital component of our national economy accounting for seven per cent of gross domestic product (GDP) in 2008. With record-high energy prices, our net export revenues represented a record 28 per cent of our merchandise trade and, although the outlook for prices appears to be lower in the near term, the energy industry will continue to be a significant driver for the Canadian economy now and into the future.

With rising prices in the first half of 2008, many energy projects became economical, despite the high production and operating costs. New projects, particularly large oil sands projects, can take years to develop and offset the natural decline of existing conventional fields. Canadian overall production of crude oil in 2008 was down slightly from 2007. Increases in oil sands production were offset because of planned and unplanned maintenance. Although exports of crude oil remained at levels seen in 2007, export revenues were much higher because of higher prices. The latter half of 2008 saw a pull back in capital spending with many projects aimed at increasing production and refining capacity either postponed or cancelled. Many agencies have reduced their supply forecasts for Canadian crude oil over the next few years given the state of the global economy.

Similar to oil, natural gas production was down. Exports declined while net export revenues were up substantially because of higher prices. The emergence of shale gas plays in the U.S. caused a supply glut which, when added to an economic slowdown and reduced demand, contributed to lower prices in the latter half of 2008. Drilling in Canada has dropped and unconventional resource plays have not yet reached their potential. The general outlook for prices remains uncertain given the shale gas supply as well as increased potential supply of liquefied natural gas (LNG) for the North American market.

Electricity industry activity during 2008 included new infrastructure additions and efforts to maintain adequate supply and reliable operation. This includes development of renewables, other supply initiatives, and emphasis on conservation and efficiency improvements. Installed capacity increased, although Canadian electricity generation decreased slightly from 2007. Over the past few years, electricity demand growth in Canada had shown some signs of moderating. Preliminary results for 2008 show annual demand declined by 1.3 per cent. This decline is slight and might be explained by slowing economic activity, energy conservation and improved efficiency. However, electricity prices increased in some Canadian jurisdictions because of the cumulative effects of higher fuel costs in recent years and higher costs for new generation and transmission. Net exports increased by four per cent, nearly double the previous five-year average. Although exports may moderate in the future in reaction to the economic slowdown, electricity exports are expected to continue to be a significant source of revenue, and imports will provide reliability for those provinces interconnected with adjacent U.S. regions.

2008 was a year of extremes. As we enter 2009, there is a sense of uncertainty with respect to the global economic picture. What remains certain, however, is that Canada has numerous opportunities with respect to technology, sustainability and environmental protection.

Energy and the Canadian Economy

2008 was a year of global economic volatility, and the Canadian economy was no exception. Canadians witnessed a unique year, one in which economic growth characterized the first half of the year and a building financial crisis dominated the latter half. Energy prices quickly rose in early 2008, reaching a peak in the summer, only to plummet later in the year. The economic slowdown which was first seen in the U.S. was soon felt in our own economy, and Canadians ended 2008 wondering how long and how deep a recession could last.

In 2008, oil hit a record high of US$147 per barrel in July, only to hit a low of US$30 in December before ending the year at US$45. Early-2008 energy prices increased energy export revenue to a record $133 billion, the highest amount ever recorded, accounting for 28 per cent of the value of all exports. Just a year earlier, energy export revenues amounted to only $93 billion (21 per cent of all exports).

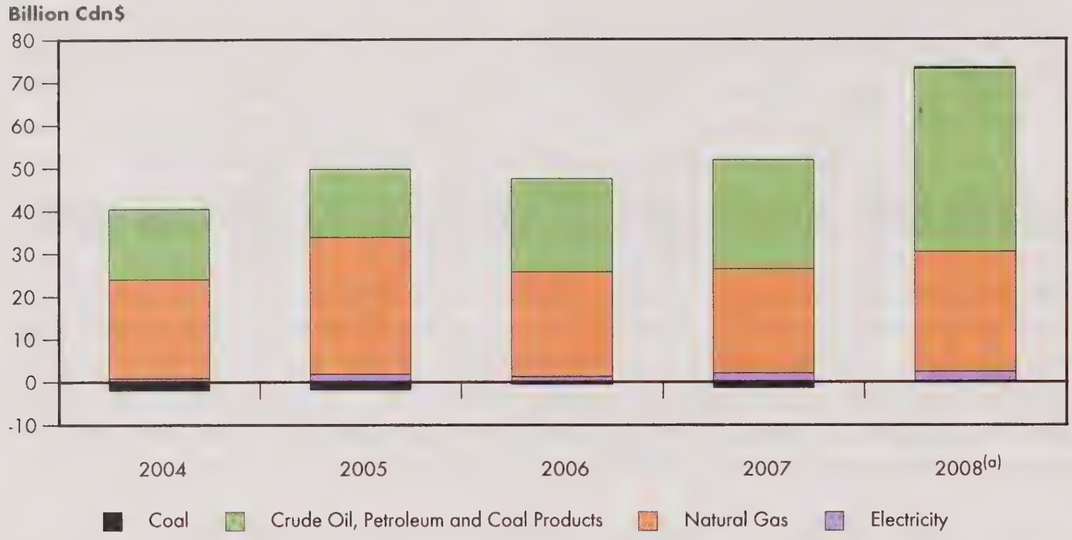
The energy industry continued to contribute significantly to the Canadian economy in 2008, despite the economic challenges presented late in the year. The Canadian energy industry accounted for seven per cent of Canada's GDP in 2008, and directly employed 363,000 people (two per cent of the Canadian labour force). The increase in oil price in early 2008 also influenced net energy export revenue (the value of energy exports minus the value of energy imports). 2008 net export revenues reached $73 billion, an increase of almost 45 per cent over 2007 levels. Historically, net natural gas export revenue has been larger than crude oil and products net export revenues; however, in 2007 net crude oil and products exports exceeded net natural gas export revenue by more than $1 billion. This trend continued into 2008, as the value of crude oil net exports surpassed the value of natural gas by almost $15 billion.

Along with oil and natural gas, net electricity export revenue also exceeded 2007 levels as a result of favourable water conditions in the main hydro-generating provinces and export growth in Ontario. Lastly, 2008 saw Canada become a net exporter of coal for the first time, creating a revenue of $360 million.

A decline in both natural gas and petroleum production contributed to a 2.1 per cent drop in total Canadian energy production. As conventional fields in western Canada were depleted, new wells coming on-stream could not keep pace. Conversely, hydroelectricity production increased 10 per cent over the past five years and other energy sources (mainly wood) actually declined slightly. Notably, the investment in wind projects has increased the energy produced from wind by almost 265 per cent from 2004 to 2008. Wind energy represents about 0.1 per cent of the energy produced in Canada. Finally, the uncertainty about energy prices has caused some pull back in investments by oil and gas producers. Detailed Canadian production trends are provided in Table 2.1.

FIGURE 2.1

Net Energy Export Revenues, 2004 – 2008



(a) Estimate

Source: Statistics Canada, NEB

TABLE 2.1

Domestic Energy Production by Energy Source (petajoules)

	2004	2005	2006	2007	2008[a]
Petroleum[b]	6 680	6 612	6 908	7 126	6 996
Natural gas[c]	6 555	6 559	6 589	6 481	6 240
Hydroelectricity	1 212	1 290	1 258	1 317	1 330
Nuclear	1 084	1 104	1 184	1 084	1 089
Coal	1 416	1 401	1 419	1 482	1 461
Wind	3	6	9	11	13
Other[d]	681	612	527	636	628
Total	**17 631**	**17 584**	**17 895**	**18 137**	**17 757**
Annual % Change	**3.9%**	**-0.3%**	**1.8%**	**1.4%**	**-2.1%**

(a) Estimates

(b) Petroleum includes crude oil and gas plant natural gas liquids (NGLs), upgraded and non-upgraded bitumen and condensate

(c) Marketable natural gas

(d) Includes solid wood waste, spent pulping liquor, wood and other fuels for electricity generation

Source: Statistics Canada, NEB

According to the International Energy Agency (IEA)[1], the United States and Canada are the largest consumers of energy on a per person basis in the world, consuming almost 200 GJ[2] per capita – the equivalent of each Canadian and U.S. resident using more then 5 000 litres (or 32 barrels) of crude oil per year. This is approximately twice the per capita energy consumption seen in other Organization

1 International Energy Agency, *Worldwide Trends in Energy Use and Efficiency*, 2008.

2 The per capita energy consumption differs among sources and heavily depends on the assumptions that go into calculating this number.

for Economic Co-operation and Development (OECD) countries. In non-OECD countries, energy consumption per capita, on average, is only 23 per cent of that in OECD countries.

Canadian energy demand trends are driven by changes in population, economic conditions, energy prices, weather, conservation, technology and consumer preferences. Over the past five years, total Canadian energy consumption has remained relatively stable, with transportation seeing the largest gains resulting in a 5.7 per cent increase in the amount of energy used between 2004 and 2008. Since the population has grown over this time there has been a modest 1.4 per cent decline in the per capita use of energy. Initial estimates suggest no overall growth of energy demand from 2007 to 2008. Demand in the residential, commercial and transportation sectors increased slightly, but was offset by the decline in the industrial sector.

Secondary energy demand, (also known as end use demand), is the energy used by the final consumer in Canada and is considered in terms of residential, commercial, industrial and transportation use. Initial 2008 estimates suggest no overall secondary energy demand growth. The industrial sector saw a decline of 1.5 per cent. Overall, 2008 total secondary energy demand is estimated to be 10 679 PJ, which is 0.2 per cent below 2007 levels (Table 2.2).

How are Energy and the Environment Connected?

Energy and environment are important issues for Canadians. A number of terms are commonly used to explain the interrelationship:

Energy Intensity: Energy Intensity is a measure of energy efficiency. It is defined as the amount of energy used to produce one unit of output or some other goal. It can be measured per unit of GDP, per person, per physical units of output, or other measures. Whichever way you measure it, lower energy intensity means less energy required to achieve the same goal, thus implying the use of more efficient technologies, devices and practices. For example:

- a more efficient space heater will use less natural gas to heat the same size house (Joules per square metre [BTU/ft^2]);
- a more efficient vehicle will use less gasoline to drive the same distance (litres/100 kilometres); and
- a more efficient paper mill will use less energy to produce the same amount of paper.

GHG Emission Intensity of Demand: GHG emission intensity measures the amount of greenhouse gases emitted into the atmosphere per unit of energy consumed (PJ). This is also known as an emission coefficient. As GHG emission intensity of demand declines, fewer GHGs are emitted for the same amount of energy used, implying the use of cleaner technologies, devices and fuels. For example: using a less emission-intensive fuel (like natural gas instead of coal) for an industrial process will result in fewer GHGs for the same amount of energy used.

GHG Emission Intensity of Output: When we measure the GHG emission intensity in terms of output, we look at emissions per 1 unit of output or some other goal. Thus, as GHG emission intensity of output declines, it means that the same goal or output can be achieved with less GHG emissions, implying reduced energy intensity and/or the use of less emission-intensive fuels. For example:

- a hybrid vehicle will create less GHG emissions while driving the same distance compared to a regular gasoline vehicle; and
- electricity generated from wind emits less GHGs into the air than electricity from fossil fuels, such as natural gas or coal, for the same amount electricity produced.

Transportation energy costs increased in 2008. For example, regular gasoline pump prices and diesel prices increased on average almost 12 per cent and 26 per cent, respectively. Canadians saw the highest gasoline and diesel prices in July. By October, total motor gasoline sales were down slightly by 0.4 per cent year over year, while diesel sales were still up by 1.2 per cent.

TABLE 2.2

Domestic Secondary Energy Consumption (petajoules)

	2004	2005	2006	2007	2008[a]
Residential[b]	1 421	1 403	1 347	1 448	1 466
Commercial	1 468	1 493	1 425	1 471	1 499
Industrial[b][c]	5 015	4 857	4 967	5 166	5 090
Transportation	2 483	2 519	2 514	2 616	2 624
Total	**10 387**	**10 272**	**10 253**	**10 701**	**10 679**
Annual % Change	**1.3%**	**-1.1%**	**-0.2%**	**4.4%**	**-0.2%**

(a) Estimates

(b) Includes biomass (wood and pulping liquor)

(c) Includes producer consumption energy use and non-energy use

Source: Statistics Canada, NEB

Advancing Clean Energy

Policies addressing climate change and air pollution continue to advance in Canada. The share of "clean" energy within the total energy mix has grown faster than the fossil fuel energy share. This trend is expected to continue. Clean or green energy is loosely defined as energy sources having minimal environmental impact, or technology that reduces the majority of harmful side effects associated with energy use. Since all energy development and use has some environmental impact, the list of what is truly clean energy is open to debate. Green energy is most often associated with renewable energy, specifically wind, solar, bio energy (i.e. ethanol, biomass) and hydro power. In addition, as nuclear power does not directly emit greenhouse gases, it is often grouped in the list of clean energy sources. Having access to all these resources places Canada in a unique position in terms of energy opportunity.

New developments in distributed generation, transmission, monitoring and controls, energy storage, and even changes to legislation for allowing electricity grid access are all components of an evolving clean and green energy future. Clean technology goes beyond power generation technology. Priorities in Canada for advancing clean energy include research and development funding for carbon capture and storage (CCS) technology. These improvements have the potential for large benefits to consumers and the environment.

Even with high fuel prices and economic challenges, transportation energy consumption increased in 2008, although by less than one per cent. When compared with previous consumption, where just a year ago Canadians increased their transportation energy consumption by four per cent (2006 to 2007), a slowing in energy consumption growth is evident. The slight increase between 2007 and 2008 is attributable to population and commercial sector growth, which helped push passenger and freight transportation demand up slightly this year.

The volatile economy that characterized 2008 is reflected in Canada's GDP, a lead indicator of our economic health. Not surprisingly, Canadian GDP was stronger in the first half of 2008. Until July, GDP was on average 1.3 per cent higher than in the corresponding months of the previous year. Combined with population growth, which Statistics Canada reports to have increased by 1.2 per cent, Canada saw a 2.5 per cent GDP increase in the service industry. In the goods-producing industry, economic growth declined, with GDP decreasing by 2.7 per cent. This decline was brought about by higher energy and material prices in the first half of the year, followed by the economic slowdown seen later in 2008. By November, GDP was one per cent lower than a year earlier, signaling the arrival of a recession[3].

3 In macroeconomics, a recession is commonly defined as a decline in a country's gross domestic product (GDP), or negative real economic growth, for two or more consecutive quarters.

On average, 2008 GDP was about 0.6 per cent higher than in 2007. To put this in perspective, the last time Canada experienced negative year-to-year growth was back in 1991 and since then (1992–2007) GDP grew by an average of three per cent per year.

Extreme volatility in energy prices as experienced in 2008 creates market distortions and results in undesirable effects on both consumers and producers. On one hand, lower prices remove the incentives for consumers to shift toward conservation. They also reverse the momentum for higher investment in energy supply and create business uncertainty. On the other hand, sharply rising prices create economic costs to consumers and the economy.

Environmental Initiatives

The year began with the advancement of several provincial and federal policies that would impact energy demand. These included expansion of clean energy and renewable energy strategies; application of new codes and standards as they relate to buildings, equipment, and appliances; and new transportation initiatives (particularly biofuel production targets and public transportation initiatives). Early 2008 also saw momentum on climate change initiatives. In March, the federal government released further details on targets and compliance mechanisms for the *Regulatory Framework for Greenhouse Gas Emissions* as it relates to large final emitters, that is, the industrial and power generation sectors. The extent and schedule of climate change measures varies greatly by province. One of the main characteristics seen in 2008 was a continuing trend in convergence of energy efficiency and conservation along with renewable energy policies.

On 23 September 2008, partners of the Western Climate Initiative (WCI) released a proposed design for a comprehensive regional cap-and-trade program to reduce the GHGs that contribute to global warming. The proposed design contains a number of recommendations, including which GHG sources should be included in a regional cap-and-trade system, implementation time frames, emission reporting requirements, carbon offsets, compliance and enforcement and other program features. The WCI cap-and-trade program covers the largest sources of emissions from each participating U.S. state and Canadian province, including power generation, industry, transportation, and residential and commercial fuel use. Along with a number of western states, British Columbia, Manitoba, Ontario and Quebec are partners in the initiative. The WCI is now the largest climate collaborative in North America, representing approximately 20 per cent of the U.S. economy, 73 per cent of Canada's economy, and 50 per cent of all GHG emissions in Canada.

In 2008, provincial legislation on climate change was introduced so that all provinces now have, at least at some level, climate change initiatives in place. Notably, both British Columbia and Manitoba legislation now include across-the-board climate change targets, aiming for GHG reductions in British Columbia of 33 per cent by 2020 (from 2007 levels), and a six per cent reduction as soon as 2012 (from 1990 levels) in Manitoba. As part of its *Energy Plan*, British Columbia also implemented a carbon-based price premium on gasoline, diesel and home heating fuels. Quebec's 2007 *Climate Change Action Plan*, had also levied a tax on fossil fuels.

The *Alberta Climate Change and Emissions Management Amendment Act* for industrial and power generation sectors, which sets a 12 per cent annual intensity reduction target, was introduced in 2008. There were further expansions of demand-side management programs in Quebec, Ontario, Saskatchewan and the Atlantic provinces.

In July, the Alberta government also announced its commitment to provide $2 billion in funding for the development of CCS technology. CCS provides an opportunity for Alberta to reduce GHG emissions while ensuring continued Albertan and Canadian economic success and growth. CCS is

Greenhouse Gas Reduction Targets

Climate change and GHGs emissions have been increasingly important issues in Canada. The Canadian and provincial governments have implemented several initiatives to address these issues. Programs under the climate change agenda include increasing energy efficiency and conservation, and promoting the use of renewable fuels. Currently, there are GHG reduction targets set in every province as well as at the federal level. There are no targets in the Territories.

Federal and Provincial Greenhouse Gas Reduction Targets

Jurisdiction	Initiative Title	Target
Federal	Turning the Corner	Reduce GHGs by 20% from 2006 levels by 2020
Alberta	Climate Change Strategy 2008	Reduce GHGs by 14% from 2005 levels by 2050
British Columbia	*Greenhouse Gas Reduction Targets Act*	Reduce GHGs by 33% from 2007 levels by 2020
Manitoba	*The Climate Change and Emissions Reduction Act*	Reduce GHGs by 6% from 1990 levels by 2012
New Brunswick	Climate Change Action Plan, 2007 - 2012	Reduce GHGs by 10% from 1990 levels by 2020
Newfoundland	New England Governors/ Eastern Canadian Premiers Climate Change Action Plan 2001	Reduce GHGs by 10% from 1990 levels by 2020
Nova Scotia	*Environmental Goals and Sustainable Prosperity Act*	Reduce GHGs by 10% from 1990 levels by 2020
Ontario	Go Green: Ontario's Action Plan on Climate Change	Reduce GHGs by 15% from 1990 levels by 2020
Prince Edward Island	New England Governors/ Eastern Canadian Premiers Climate Change Action Plan 2001	Reduce GHGs to 1990 levels by 2010, and 10% below 1990 levels by 2020
Quebec	Quebec and Climate Change: A Challenge for the Future	Reduce GHGs by 6% from 1990 levels by 2012
Saskatchewan	Saskatchewan Energy and Climate Change Plan 2007	Stabilize GHG emissions by 2010, reduce GHGs by 32% from current levels by 2020 and 80% from current levels by 2050

a scientifically-proven technology that will reduce carbon dioxide (CO_2) emissions from large scale operations including oil sands facilities, and coal-fired electricity generation. The initial goal is to store five Mt of CO_2 in the ground annually by 2015[4].

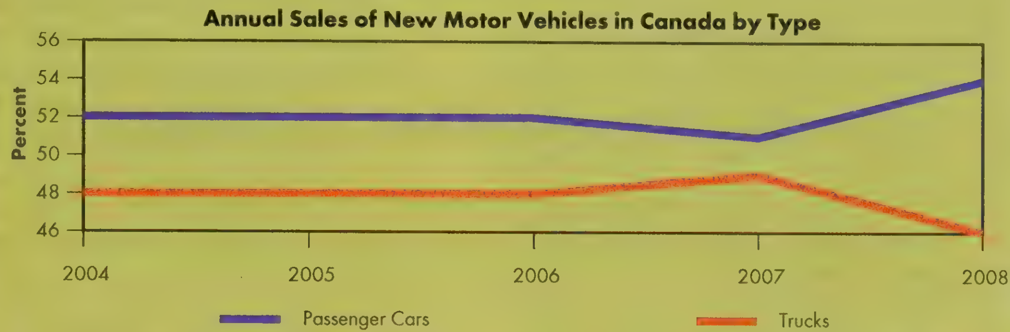
4 Earth's most abundant GHGs are:

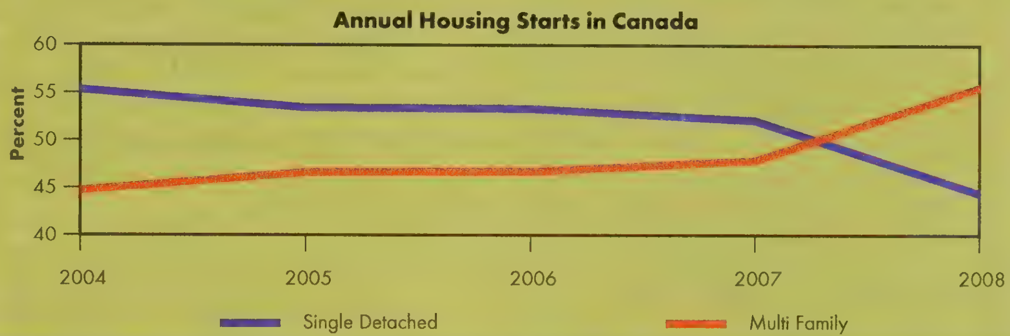
- water vapor (H_2O), which contributes 36-72 per cent of the Earth's greenhouse effect;
- CO_2, which contributes 9-26 per cent of the Earth's greenhouse effect;
- methane (CH_4), which contributes 4-9 per cent of the Earth's greenhouse effect; and
- ozone (O_3), which contributes 3-7 per cent of the Earth's greenhouse effect.

Other GHGs present at low concentrations include nitrous oxide (N_2O), sulphur hexafluoride (SF_6), perfluorocarbons (PFCs), and hydrofluorocarbons (HFCs). All of these gases, with the general exception of the last three, can be of natural or industrial origin.

Consumer Behavioural Trends

There are several trends affecting consumer behaviour, including energy prices, disposable income and the health of the economy. Consumers are also becoming more aware of how their choices are affecting the environment. The changing trends in consumer behaviour impact energy consumption.





2.1 Looking Ahead

In Canada, energy consumption growth is expected to continue to slow in response to sluggish economic conditions. Global economic conditions, energy price concerns, potential supply constraints and heightened environmental awareness could influence consumer spending habits and therefore energy demand trends. New government programs and policies are also expected to impact energy demand trends over the next few years. While governments continue to make strides with legislation and consumer awareness initiatives, reductions in Canadian energy consumption rely on behavioural shifts at the individual level. Transformational changes in lifestyles will slowly bring about change and result in stabilized, if not reduced, energy consumption.

Already there are signs that changes in consumer preferences are starting to occur. Canadians increasingly take into consideration environmental costs associated with their purchasing decisions. For example, recent years have seen a significant shift in new vehicle purchasing trends with Canadians' more likely to opt for smaller economy vehicles over larger trucks and sport utility vehicles (in 2008, 54 per cent of all new vehicle sales were passenger cars and 46 per cent were trucks and sport utility vehicles, a change from 51 per cent and 49 per cent respectively in 2007). If this is a stable shift in consumer preferences, then we would expect to see the emergence of a more fuel efficient vehicle fleet, which would have implications for future energy consumption. Canadians housing choices are also affecting demand. According to the Canadian Mortgage and Housing Corporation (CMHC), in 2008 the share of multi-family dwelling construction exceeded single-family housing starts at 56 per cent of all housing starts that year (up from 48 per cent in 2007). CMHC expects this trend to continue into 2009 and such trends should decrease the energy intensity of the residential sector. Over time, these changes will directly impact energy demand in the residential and passenger transportation sectors and as a result GHG emissions will also be impacted.

Upstream Oil and Gas Activity

Measures of upstream oil and gas activity include dollars spent to acquire land rights, the number of active seismic crews, the number of active drilling rigs, number of wells drilled and the capital expenditures involved.

Cost pressures associated with strong economic growth continued from 2007. In mature basins like the Western Canada Sedimentary Basin (WCSB), the cost to produce natural gas was further increased in 2008 as new wells, on average, produced at lower rates and recovered less energy. These cost pressures, however, were offset by surging commodity prices for both oil and gas through the first seven months of the year, with oil reaching a record US$147/bbl and natural gas peaking at over US$13/MMbtu in July before prices reversed course and dropped dramatically by year-end. By the close of 2008, oil slid to US$40/bbl and gas prices landed at US$6/MMbtu.

Petroleum Rights in Canada

Rights to oil and gas resources are owned or shared by provincial, territorial, federal, or First Nation governments. Crown rights are administered and dispensed by regulatory bodies, usually at auctions, to ensure competition for extraction of oil and gas and that Canadian citizens receive fair value. In the western provinces and for Crown lands in Ontario, Crown rights are leased to operators who pay the highest bonus and the revenues generated by the auction go directly into provincial coffers. In the territories of northern Canada and in Maritime provinces, including offshore areas, regulatory bodies use auctions to solicit commitments for industry spending and do not directly generate significant revenue for respective governments. In Quebec, land is licensed by application, except for offshore areas, where there is a call for bids.

Finally, any oil or gas produced under a Crown lease usually generates royalty payments for governments, although royalty rates vary from jurisdiction to jurisdiction.

Acquisition of petroleum rights in western Canada was the main upstream oil and gas story as high oil and gas prices pushed industry to spend a total of $5 billion, nearly double the amount of land bonuses received in 2007. British Columbia led all provinces in land bonuses received with a provincial record of $2.7 billion for 757 000 hectares ($3 518/ha) compared to $1.1 billion for 596 000 hectares ($1 758/ha) in the prior year. Most activity in British Columbia was focused on the Peace River region, where $1.3 billion ($11 000/ha) was spent obtaining drilling rights to Montney Formation tight gas, and areas north of Fort Nelson, where $1.1 billion ($4 000/ha) was spent obtaining rights to Horn River Basin gas shales.

Saskatchewan also set a new record, acquiring $1.1 billion in land bonuses for 766 000 hectares ($1 461/ha), more than quadrupling the previous year's record of $250 million. The majority of activity was in southeast Saskatchewan, mostly for the Bakken oil play, where $917 million was spent for 496 000 hectares ($1 848/ha).

Alberta took in $1.2 billion in land bonuses, continuing the steady decline from $3.4 billion in 2006. Land bonuses for leases in the oil sands declined by over 50 per cent for the second straight year, to $288 million for 1.7 million hectares, averaging just $174/ha. This

is down significantly from $650 million for 1.3 million hectares ($573/ha) in 2007 and $1.9 billion for 1.5 million hectares ($1 216/ha) in 2006. The decline is attributed to the most prospective areas of the oil sands already being under lease, negative industry response to the new royalty framework[5], and Alberta not having the hot non-bitumen resource plays like Saskatchewan and British Columbia.

The Northwest Territories received over $1.2 billion in exploration commitments, mainly from a single land sale in which BP Canada committed to $1.2 billion in exploratory spending for a parcel in the Beaufort Sea. However, Yukon had two land sales in 2008 and received zero bids. Offshore Nova Scotia received commitments for $353 million in exploration expenditures while the Canada-Newfoundland and Labrador Offshore Petroleum Board received commitments for almost $319 million in expenditures.

Land Matters Consultation Initiative: Listening to the Public Interest

In 2008, the National Energy Board met with more than 400 Canadians, including landowners, industry representatives and government departments, as part of our Land Matters Consultation Initiative (LMCI).

The LMCI provides a Canadian forum for discussing land matters to help improve understanding of the various issues and also generate new ideas to improve the way in which these issues are incorporated into the Board's public interest considerations. The initiative also provides an opportunity for companies and landowners to foster and strengthen effective working relationships.

The LMCI is divided into four streams:

1. company interactions with landowners;
2. improving the accessibility of NEB processes;
3. pipeline abandonment – financial issues; and
4. pipeline abandonment – physical issues.

Further information on the LMCI can be found on our web site at www.neb-one.gc.ca.

The average number of seismic survey crews active in Canada grew slightly from 2007, from eight to nine. Continued low seismic crew activity since 2007 indicates that 2009 will not see a resurgence in exploration activity. The oil and gas industry completed 20,721 wells across Canada in 2008, eight per cent higher than the number of wells completed in 2007[6].

The rise in commodity prices caused oil- and gas-related activity in western Canada to remain fairly strong in 2008 with drilling activity, often measured in terms of drilling days or the number of active rigs per week or month, increasing. While the capacity of the drilling rig fleet in western Canada shrank in 2008, averaging 878 rigs after peaking at 901 in 2007[7], monthly active rig utilization increased to an average 364 versus 339, as did total operating time, to almost 133,000 from 120,000 days. However, this was still significantly less than the 504 rig average and 158,000 operating days in 2006. Figure 3.1 provides the weekly active rigs in western Canada. Note that there was a rapid drop in drilling activity in December 2008 as a result of the economic downturn.

Approximately 16,300 oil and gas wells were drilled in western Canada in 2008, a ten per cent decline from 2007 (Figure 3.2) and something that appears to be at odds with the increase in rig activity and operating days described above. This discrepancy is explained by the increased use of

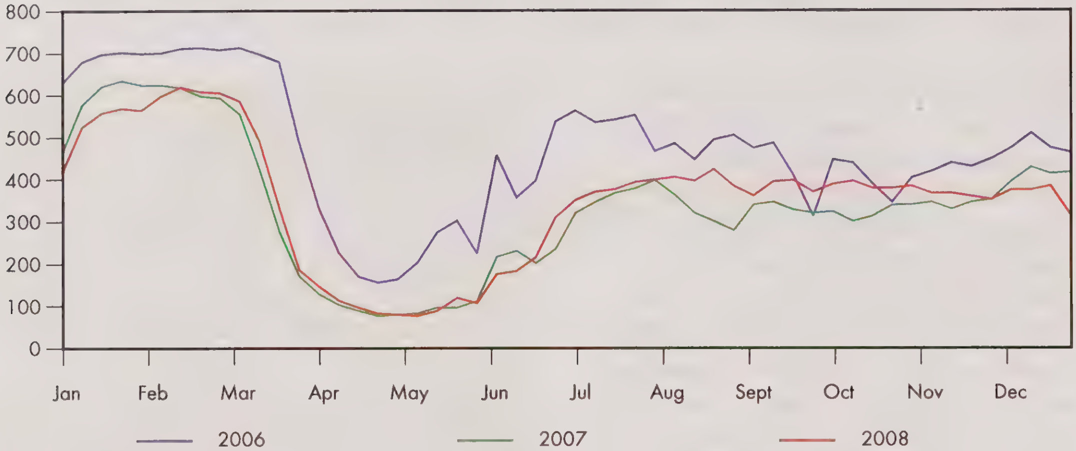
5 The New Royalty Framework (NRF), announced in October of 2007 and applicable to all conventional oil and gas wells drilled on or after 1 January 2009, increased the amount of royalty to be paid per well depending on the price of oil and gas and well production. In November 2008, in response to the global economic downturn and to encourage drilling in the province, the Alberta Government announced a five-year transitional option for oil and gas wells drilled on or after 19 November 2008, which allows a company to keep the previous royalty framework on a well-by-well basis. On 1 January 2014, all wells will automatically switch to the NRF.

6 *Nickle's Daily Oil Bulletin*, December drilling lower, completions higher, 12 January 2009.

7 Canadian Association of Oilwell Drilling Contractors, Average Monthly Drilling Rig Count – Western Canada.

FIGURE 3.1

Weekly Active Rigs in WCSB



Source: Nickle's Daily Oil Bulletin

deep horizontal wells with long lateral reaches to exploit Bakken oil in Saskatchewan and shale gas in British Columbia, which take significantly more time to drill when compared to vertical wells. Supporting this conclusion is significant growth to the average length of wells drilled in 2008 over wells drilled in 2007, increasing to 1 290 metres from 1 194 metres. This shift toward Saskatchewan Bakken oil and British Columbia shale gas was further demonstrated by a redistribution of exploration by geographic region. The number of wells drilled in Saskatchewan increased by 22 per cent, rising to 3,898 from 3,202, while the number of wells drilled in British Columbia remained relatively unchanged, rising slightly to 847 from 843, despite the significant decrease in total wells drilled across western Canada. The number of wells drilled in Alberta took the brunt of this drop, falling 17 per cent to 11,569, down from 14,001.

The number of oil wells drilled in the year increased by five per cent, with natural gas drilling down by 17 per cent. As a result of the ongoing decline in gas economics relative to oil, the percentage of wells directed to natural gas slid to 64 per cent from 69 per cent.

Total oil and gas capital expenditures in Canada rose by two per cent to an estimated $43.9 billion. Capital spending associated with oil sands projects rose to an estimated $17.3 billion, eight per cent more than 2007 levels. This increase was driven in part by cost overruns rather than new projects. Conventional oil and gas expenditures fell to an estimated $26.6 billion, two per cent less than 2007 and the third straight year of decline.

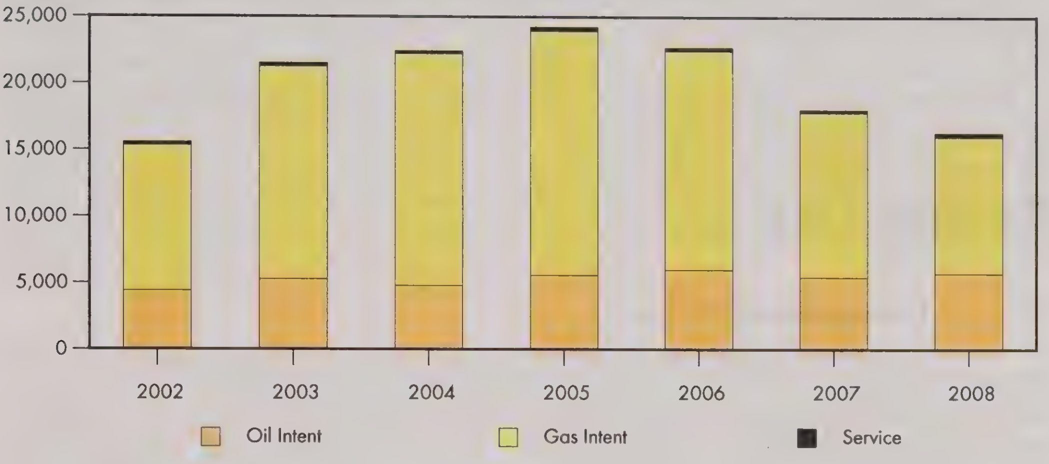
Technological Achievements in Drilling and Production

The application of hydraulic fracturing, a technique where induced high pressures are used to crack the reservoir and create a network of fractures through which oil or gas can flow more readily, has been in practice for decades. Horizontal drilling, another technique to improve recovery, has been in common usage since the mid 1990s. However, using them both together had been problematic until the last few years. Previously, the fracturing could not be easily controlled and long segments of the horizontal well would remain untouched. Now, operators can isolate segments of the horizontal well and fracture each segment sequentially in a technique called-multi stage fracturing, turning long stretches of what was tight oil bearing or gas bearing rock into a prolific reservoir.

These combined techniques are being successfully used to produce natural gas from gas shales as well as from tight sandstones of Alberta and northeast British Columbia. These techniques have also led to the successful recovery of oil from the Bakken oil play in southeastern Saskatchewan.

FIGURE 3.2

Number of Wells Drilled - Western Canada, 2002 - 2008



Source: NEB

3.1 Looking Ahead

Low commodity prices, cost overruns and a lack of skilled labour have already resulted in numerous oil sands projects being cancelled or deferred as producers adjusted their operating budgets for 2009. Statistics Canada expects that 2009 oil and gas capital expenditures will fall 21 per cent from 2008 levels[8], the largest drop being in the oil sands sector, which they project will decrease 31 per cent.

It is expected that the average number of active rigs in western Canada will drop substantially in 2009 from 2008 levels. The first twelve weeks of 2009 have already seen the average number of active rigs in western Canada down 33 per cent from the first twelve weeks of 2008[9]. This represents a 33 per cent reduction from 2007 levels and a 45 per cent reduction from 2006. The Petroleum Services Association of Canada has projected that 2009 will see a 21 per cent overall drop from 2008 levels in the number of wells drilled and is warning about substantial layoffs in the oil and gas services sector.

Furthermore, it is unlikely there will be high levels of land activity in 2009 with most of the petroleum rights for core areas of the gas shales of British Columbia, the oil sands of Alberta, and the Bakken oil play in southeast Saskatchewan already leased from past sales. Low commodity prices, forecasted to persist through the year, will also impact industry spending on future lease acquisitions.

With significantly reduced natural gas drilling in 2009, Canadian natural gas production is expected to be lower than in 2008, even with increased drilling in such high-productivity natural gas plays like the Horn River Basin and Montney gas shales. While oil sands production is forecasted to increase, conventional light and heavy crude oil production will continue their natural annual decline of roughly three per cent, leading to a small overall increase in Canadian oil production.

8 Statistics Canada, *Private and public investment 2009 intentions*, 2009.

9 *Nickle's Daily Oil Bulletin*.

Crude Oil

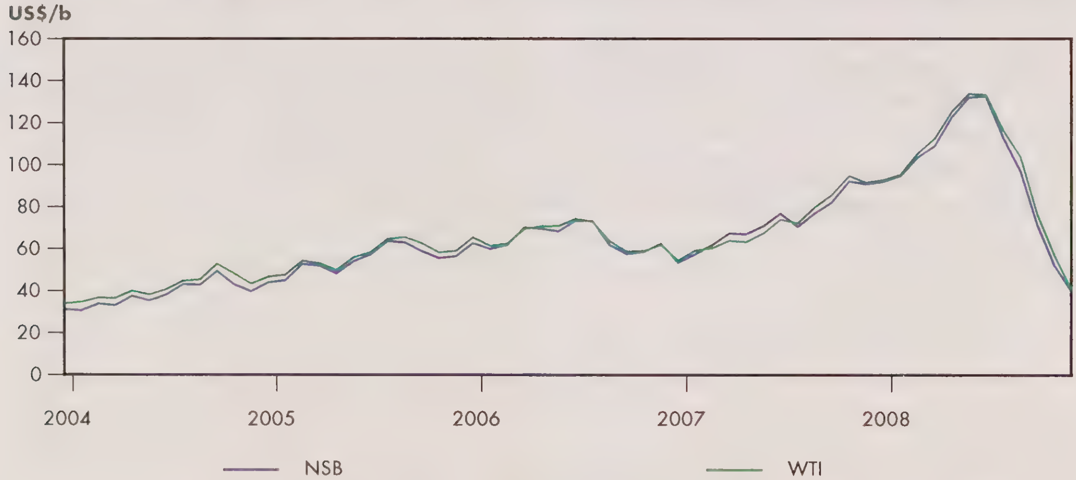
4.1 International Markets

2008 was an extraordinary year in crude oil markets. On the first trading day of the year, the near-month West Texas Intermediate (WTI) contract broke US$100/bbl (intra-day) for the first time. In July, the WTI reached an all-time high of US$147/bbl (intra-day) before a slowing global economy caused prices to tumble, ending the year at US$45/bbl. WTI averaged US$100/bbl over the year, compared to about US$73/bbl in 2007. Figure 4.1 shows historical prices for WTI at Cushing, Oklahoma, and North Sea Brent (NSB), a common benchmark for European crude oil pricing.

The first half of 2008 was characterized by continued growth in global demand for crude oil and petroleum products. While rising prices were contributing to decreased demand in OECD countries, demand continued to grow in emerging economies including China and India partly due to government fuel subsidies. In the context of rising demand, global supplies remained tight and OECD inventories remained below the five-year average, providing fundamental support for prices. With low Organization of Petroleum Exporting Countries (OPEC) spare capacity, the market paid special attention to ongoing geopolitical threats to supply, particularly in Iraq, Iran and Nigeria, at times producing significant price swings. Superimposed on the tight supply and demand situation, investment money flowed into commodities and the oil market specifically, driven by attractive returns. This increased investment also contributed to greater volatility in oil prices. The U.S. dollar decline over the first half of the year also contributed to higher oil prices.

FIGURE 4.1

WTI and Brent Oil Prices, 2004 – 2008



Source: Energy Information Administration (EIA)

While much of the rapid rise in oil prices during the first half of 2008 can be attributed to market response to tight supply and geopolitical events, the second half of 2008 became a market focused on falling demand. The rapidly intensifying financial and credit crisis caused tremendous wealth destruction in the U.S. and around the world and resulted in greatly reduced economic activity. By early fall, most economists believed that the world was on the brink of a serious economic downturn. At the end of September, global crude oil inventories began to build and WTI had fallen to about US$100/bbl. In an effort to stem this effect, OPEC met in October 2008 and agreed to a substantial production cut of 238 000 m^3/d (1.5 MMb/d) and on 17 December 2008 agreed to a further cut of 349 000 m^3/d (2.2 MMb/d), effective 1 January 2009. Despite OPEC's announced production cuts and as the economic outlook worsened, prices continued to fall and inventories continued to build. The WTI near-month contract ended the year at US$45/bbl.

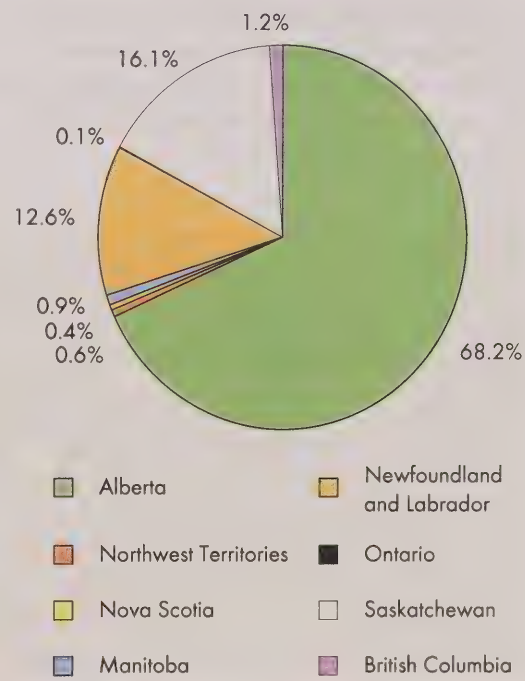
4.2 Canadian Oil Production and Reserves Replacement

In 2008, Canadian production of crude oil and equivalent averaged 429 000 m^3/d (2.7 MMb/d), a decrease of nearly two per cent from 2007 levels. Oil sands production grew by only 2.5 per cent, because of considerable down time for maintenance and tying in new facilities. This was more than offset by falling conventional crude oil production in the WCSB and on the east coast offshore where production decreased by eight per cent, reflecting natural pool decline as well as some maintenance down time at the Terra Nova field. Figure 4.2 illustrates crude oil production by province.

In 2008, production offshore Newfoundland and Labrador was 54 400 m^3/d (341 Mb/d), down from 58 600 (369 Mb/d) because of natural pool declines. Figure 4.3 illustrates east coast production. In western Canada, crude oil and equivalent supply remained essentially unchanged from 2007 levels. Conventional light crude oil production also remained steady, with production buoyed by higher oil prices in the first half of the year, and with new production from the Bakken play in Saskatchewan reversing previous decline trends. Conventional heavy crude oil production levels decreased by four per cent, in line with the general decline that has developed since production peaked in 2001. Figure 4.4 illustrates crude oil production by type.

FIGURE 4.2

Crude Oil and Equivalent Production by Province



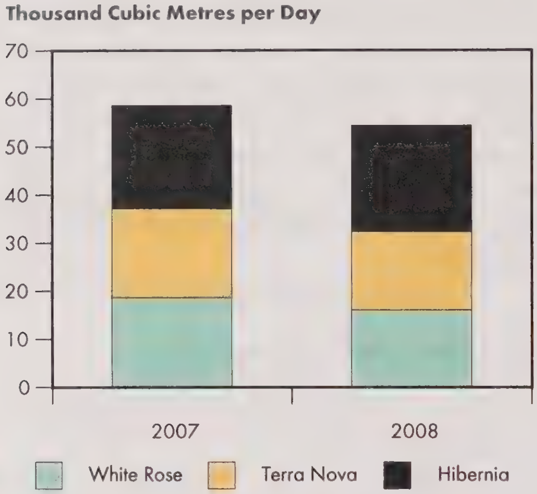
Source: NEB

While remaining conventional established reserves are reduced by production each year, these reductions are offset to some degree by new discoveries, extensions to existing pools and revisions to reserve estimates in existing pools. From 2002 to 2006, cumulative additions to established reserves of conventional light and heavy crude oil replaced 84 per cent of production (Table 4.1). In 2007, 66 per cent of production of conventional crude oil was replaced.

The NEB's estimate of total remaining Canadian conventional crude oil and crude bitumen reserves at year-end 2007 (the last year for which nearly-complete data is available) is 28.1 billion cubic

FIGURE 4.3

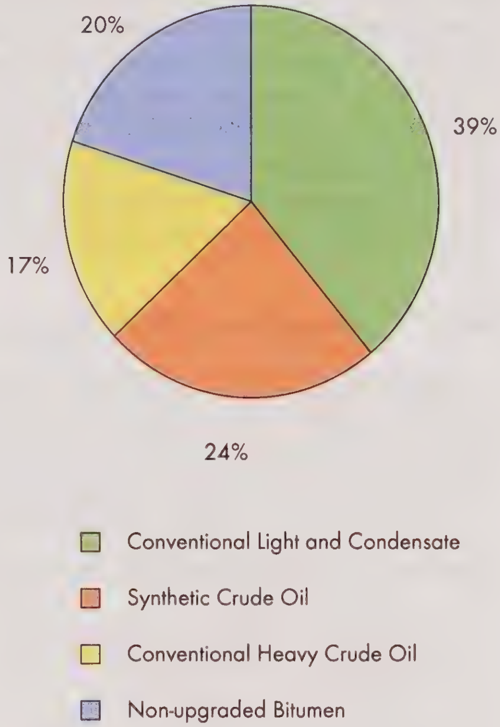
East Coast Production, 2007 – 2008



Source: Canada – Newfoundland and Labrador Offshore Petroleum Board

FIGURE 4.4

Crude Oil and Equivalent Production by Type



Source: NEB

metres (176.8 billion barrels), an increase of less than one per cent compared with 2006. Estimates of remaining established conventional crude oil reserves in Canada decreased by four per cent to 614.4 million cubic metres (3 871 million barrels) for 2007. Most of this decrease can be attributed to production significantly outpacing reserves additions in 2007. The remaining established crude bitumen reserves decreased slightly to 27.5 billion cubic metres (172.9 billion barrels) reflecting 2007 bitumen production (Table 4.2).

Reserves and Production Terminology

Crude oil can vary greatly in its composition and characteristics, and a distinction is made based on method of extraction from underground reservoirs.

Conventional crude oil is liquid in its natural state and can flow freely to a well bore and can be recovered using normal production practices.

Unconventional crude oil, or crude bitumen, is usually found in a semi-solid, viscous state, will not flow freely to a well, and requires the application of heat or dilution with solvents to be recovered. When deposited close to the surface, crude bitumen contained in oil sands can be recovered using direct mining methods. These terms are often used to describe established reserves and annual production data.

TABLE 4.1

Conventional Crude Oil Reserves, Additions and Production, 2003 – 2007 (million cubic metres)

	2003	2004	2005	2006	2007	Total
Additions[(a)]	60.8	66.9	134.7	27	50	339.4
Production	85.6	82.7	78.8	82.1	76	405.2
Total Remaining Reserves	**663**	**640**	**696**	**640**	**614**	
Total Remaining Reserves (millions of barrels)	**4 172**	**4 027**	**4 382**	**4 033**	**3 871**	

(a) White Rose added in 2002

Source: Provincial Energy Agencies, Offshore Petroleum Boards, NEB

TABLE 4.2

Estimates of Established Reserves of Crude Oil and Bitumen at 31 December 2007 (million cubic metres)

Conventional Crude Oil	**Initial**	**Remaining**
British Columbia[(a)]	129.0	19.7
Alberta[(b)]	2 751.4	240.5
Saskatchewan[(c)]	890.1	170.0
Manitoba[(d)]	45.8	7.7
Ontario[(e)]	14.8	1.6
Northwest Territories, Nunavut and Yukon		
Arctic Islands and Eastern Arctic	0.5	0.0
Mainland Territories – Norman Wells and Cameron Hills	52.9	13.7
Nova Scotia – Cohasset and Panuke[(d)]	7.0	0.0
Newfoundland – Hibernia, Terra Nova and White Rose[(d)]	299.1	161.2
Total	**4 190.6**	**614.4**
Total (millions of barrels)	**26 400.8**	**3 870.7**
Crude Bitumen		
Oil Sands – Minable Upgraded Crude[(f)]	5 590.0	4 962.0
Oil Sands – Bitumen[(f)]	22 802.0	22 486.0
Total	**28 392.0**	**27 448.0**
Total (millions of barrels)	**178 870.0**	**172 922.0**
Total Conventional and Bitumen	**32 582.6**	**28 062.4**
Total Conventional and Bitumen (millions of barrels)	**205 270.4**	**176 793.1**

(a) British Columbia Ministry of Energy & Mines and NEB common database.

(b) Alberta Energy Resources Conservation (ERCB) Board and NEB common database.

(c) Canadian Association of Petroleum Producers/NEB estimates 2006.

(d) Provincial Agencies or Offshore Boards, NEB estimate for Manitoba 2006.

(e) Canadian Association of Petroleum Producers.

(f) ERCB Report – ST 98 2008.

Note: totals may not add due to rounding.

4.3 Oil Sands

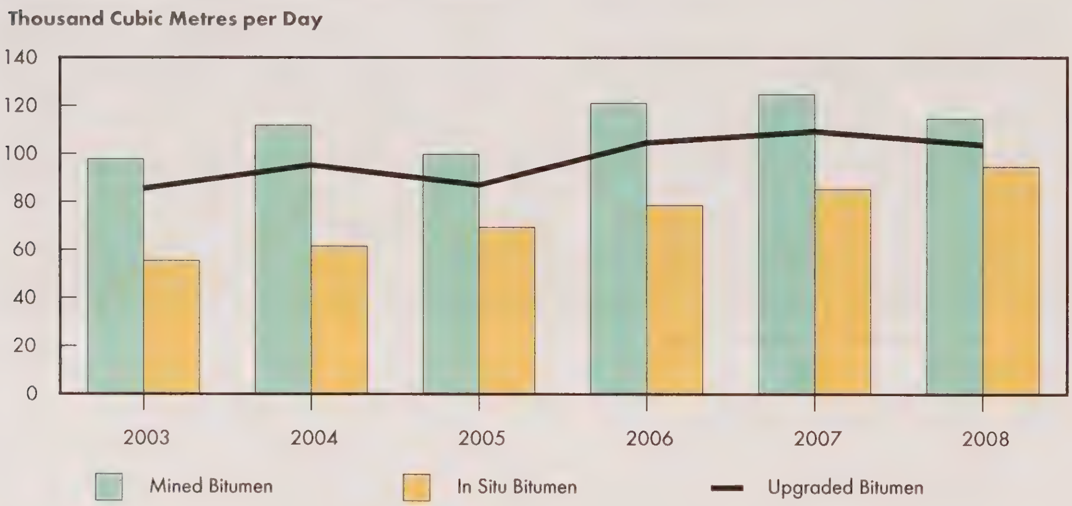
In early 2008, oil sands production in Alberta continued to expand and attract investments from domestic and foreign sources. Investment in Canada's oil sands has been appealing given the size of the resource, the stable political and investment climate, and the diminishing number of investment opportunities in other oil producing countries, owed part to increasing resource nationalization. High crude oil prices facilitated oil sands development for the majority of the year; however, volatile financial markets, increased capital costs and an abrupt fall in oil prices late in the third quarter slowed down several projects and initiated many project postponements. Oil sands spending in 2008 is estimated to be about $17.3 billion.

In 2007, adjustments to Alberta royalties and changes to federal taxation measures altered the economic conditions of oil sands projects. Royalty rates are now to be determined by a sliding scale based on WTI prices, expressed in terms of real Canadian dollars. At prices up to Cdn$55/bbl, royalty rates remain identical to the previous royalty scheme, at one per cent pre-payout and 25 per cent post-payout. At prices above this point, rates increase, reaching a maximum of nine per cent pre-payout and 40 per cent post-payout at Cdn$120/bbl. All royalty payments remain both tax-deductible and eligible as expenditures for the purposes of calculating payout. Both Suncor Energy Inc. and Syncrude Canada Ltd. had prior long-term contracts, signed in 1997 with the Alberta Government, but have come to terms with the province regarding application of the new royalty rates. The new royalty regime was implemented in January 2009.

In 2008, bitumen production from mining and in situ operations totalled 209 000 m^3/d (1.3 MMb/d), down less than one per cent compared with 2007. In situ bitumen production increased by 11 per cent to 94 600 m^3/d (596 Mb/d) (Figure 4.5), while bitumen from mining operations decreased by eight per cent to 115 000 m^3/d (721 Mb/d). The amount of bitumen production that was upgraded to synthetic crude oil decreased by five per cent to 104 000 m^3/d (653 Mb/d). Non-upgraded bitumen is blended with other heavy and light crudes and condensate for transport by pipeline to refineries. Despite rising construction costs, labour shortages and the economic downturn, several in situ and mining projects commenced operations in 2008. OPTI/Nexen's Long Lake project, which couples a surface upgrader with an in situ steam assisted gravity drainage (SAGD) operation, is the first oil sands project to utilize gasification of bitumen residue, or asphaltenes, to produce synthetic gas (syngas)

FIGURE 4.5

Crude Bitumen Production, 2003 – 2008



Source: Energy Resources Conservation Board (ERCB)

within the upgrader, hence minimizing the need to purchase and use natural gas for steam generation. In early 2009, OPTI/Nexen began first production of sweet synthetic crude at Long Lake. Canadian Natural Resources Limited Horizon mining project was brought online in the third quarter of 2008, but because of escalating costs and volatile oil prices, further expansions have been delayed. The Horizon project is expected to produce up to 17 500 m³/d (110 Mb/d) within the next year to 18 months.

In 2008, Syncrude production volumes decreased because of operational disruptions, severe weather conditions and scheduled maintenance in the third quarter. Annual production is estimated to be 45 900 m³/d (289 Mb/d). This is a 5.2 per cent decrease from 2007 production.

Suncor oil sands production averaged 36 249 m³/d (228 Mb/d) in 2008, compared with 37 400 m³/d (236 Mb/d) in 2007. This decrease primarily reflects the impact of scheduled and unscheduled maintenance, labour shortages and a November fire in Suncor's Upgrader 2 vacuum unit. Suncor completed an expansion of its Millennium Coker project in 2008 and expects to increase production in 2009.

Land Reclamation

Syncrude Canada's Gateway Hill, a 104 hectare parcel of land, received the first ever industry certification of reclamation from the Alberta government in 2008.

A reclamation certificate is only issued when the land is no longer used for any oil sands purposes and is fully reclaimed meaning it can sustain vegetation and wildlife. This parcel of land, once used for oil sands mining processes, is now a popular area for hikers, who hike the Matcheetawin trail to experience the integrated forest and wetlands of the reclaimed land.

Reclamation at Gateway Hill began in 1983 and continued through 2008. Currently, Syncrude leads the oil sands industry in land reclamation and has reclaimed over 500 hectares of land.

Production at the Athabasca Oil Sands Project, a company consisting of Shell Canada Limited (60 per cent), Marathon Oil Canada Corporation and Chevron Canada (20 per cent each) is estimated to be 19 866 m³/d (125 Mb/d) in 2008, a decline of three per cent compared with 2007. Planned and unplanned maintenance as well as operational issues were the main reasons cited for the decline in production.

4.4 Crude Oil Exports and Imports

Canada is a net crude oil exporter with the bulk of its exports going to the U.S. Canadian refineries in British Columbia, Alberta, Saskatchewan and Ontario receive crude oil supplies from western Canada with the balance exported, mainly by pipeline, to markets in the U.S. Refineries in Ontario, Quebec, and Atlantic provinces import some crude oil to meet demand because it is more economic to do so. As a result, some Atlantic crude oil production is consumed domestically with the balance exported primarily to the U.S.

In 2008, crude oil exports averaged approximately 285 000 m³/d (1.79 MMb/d) which represents a year-on-year decrease of less than one per cent. Light crude oil exports, which include pentanes plus and synthetic crude oil (upgraded bitumen), represented 28 per cent of all exports with the remaining 72 per cent comprised of exports of heavy crude oil[10].

10 The NEB updated the crude characteristics in the Oil Export System to accurately reflect changes in sulphur content and API gravity. Some light crude oil streams became medium crude oil streams because their API gravities fell below the 30 degree API threshold. This has increased the relative volume of medium/heavy exports and decreased the relative volume of light exports.

The estimated value of crude oil exports for 2008 is \$60 billion compared with \$44 billion in 2007. The estimate is based on approximated export prices of \$641 and \$540/m^3 (Cdn\$102 and Cdn\$86/bbl) for light crude oil and heavy crude oil, respectively (Figure 4.6).

Heavy and light crude oils are traded in separate markets, and accordingly the prices for each vary as a result of the supply and demand for each crude type. Heavy crude has a smaller market, higher refining costs, yields lower volumes of higher valued products such as gasoline and, as a result, is usually discounted. The differential typically narrows in the summer months because of the higher demand for heavy crude oil during asphalt season and widens again in September.

Oil Pipeline Capacity Expansions

Construction began in 2008 on two Board approved crude oil pipelines.

Enbridge began construction on its Clipper pipeline which, when it is slated to begin operation in 2010, will have an initial capacity of about 71 500 m^3/d (450 Mb/d). TransCanada began construction on its 94 000 m^3/d (591 Mb/d) Keystone pipeline system which is also expected to begin operations in 2010.

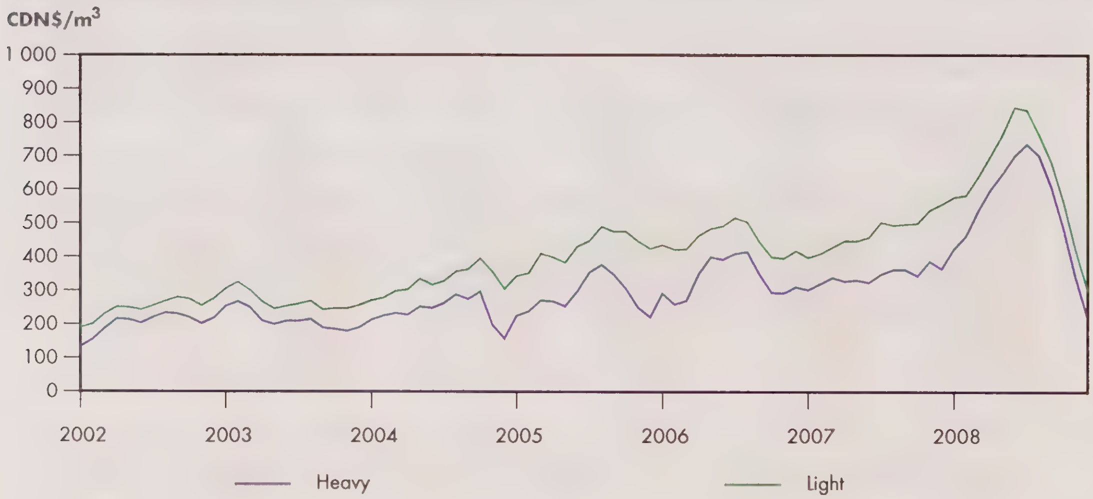
In addition to the commencement of construction on these two major export pipelines, Kinder Morgan expanded capacity on its Trans Mountain pipeline by 6 400 m^3/d (40 Mb/d). Industry and government are working in partnership to ensure that responsible and economic development of resources can occur by gaining access to new and existing markets through pipeline capacity expansions.

On a dollar basis, the light–heavy differential averaged \$101/m^3 (Cdn\$16/bbl) during 2008, wider than the typical level as many road improvement projects were deferred because of record crude prices. Since the summer, the differential has narrowed as a result of sharply declining crude prices and lower light crude prices due to weak gasoline demand.

Anticipated and actual capacity constraints on major oil export pipelines also contributed to the widening differential. The Enbridge, Express/Platte and Trans Mountain systems were operating at or near capacity throughout 2008 with some apportionment experienced in the first and last quarters of the year. When refiners in the U.S. expect or anticipate pipeline capacity constraints, which can result in not having crude when it is needed, they tend to offer a lower price for that crude oil.

FIGURE 4.6

Light and Heavy Crude Oil Export Prices



Source: NEB

In 2008, the Board approved a number of oil pipeline applications, including Enbridge Southern Lights (OH-3-2007), Alberta Clipper (OH-4-2007) and the Line 4 Extension (OH-5-2007). TransCanada's Keystone Cushing Extension (OH-1-2008) project, which will allow Canadian crude oil to reach Cushing, Oklahoma, was also approved.

Other pipeline projects proposed in 2008 included the Enbridge Gateway project which proposes to ship Canadian crude to new markets in Asia using oil tankers, the Enbridge Trailbreaker project which proposed a re-reversal of the Enbridge Line 9 pipeline to carry Canadian crude to the U.S. east coast and Gulf Coast, and the TransCanada Keystone XL project which proposes a pipeline to the U.S. Gulf Coast. Due to lack of shipper support, Enbridge Trailbreaker was subsequently postponed.

Canada remained the number one supplier of crude oil to the U.S. followed by Saudi Arabia and Mexico[11]. According to the EIA, the U.S. imported an average of 1.5 million m^3/d (9.7 MMb/d) giving Canada approximately 20 per cent of the import market. Canada became the number one supplier of heavy crude oil to the U.S., surpassing Mexico which continues to experience declines in production. Sixty per cent of total Canadian crude exports went to the U.S. Midwest (PADD II) market, making it the largest consuming export market for Canadian crude oil.

Over 90 per cent of eastern Canadian crude oil exports were delivered to the U.S. east coast (PADD I). The remaining eastern Canadian exports were delivered to the U.S. Gulf Coast (six per cent) and the Caribbean (three per cent). Given the proximity and relationship Canada has with the U.S., the U.S. will remain a major export market in the future. Table 4.3 contains a breakdown of crude oil exports by type and destination.

TABLE 4.3

Crude Oil Exports by Type and Destinations – 2008 (volume – m^3/d)

Market	Light	Medium	Heavy	Synthetic	Blended Bitumen	Total
PADD I	24 068.9	219.5	5 539	1 249.6	278.3	31 355.3
PADD II	12 027.3	19 647.0	67 312.7	37 468.4	39 694.8	176 150.2
PADD III	1 791.5	268.8	4 011.4	256.3	7 914.2	14 242.2
PADD IV	3 916.2	3 115.6	20 947.4	6 816	3 108.6	37 903.8
PADD V	14 201.5	0.0	0.0	7 173.9	2 750.2	24 125.6
Total U.S.	**56 005.4**	**23 250.9**	**97 810.5**	**52 964.2**	**53 746.1**	**283 777.1**
Other	633.9	0.0	0.0	415.4	250.5	1 299.8
Total	**56 639.3**	**23 250.9**	**97 810.5**	**53 379.6**	**53 996.6**	**285 076.9**

Notes:

PADD - Petroleum Administration for Defense District (see Figure 4.7)

Light - greater than 30 API

Medium - between 25 and 30 API

Heavy - less than 25 API

Synthetic - upgraded bitumen of any API

Blended Bitumen - Bitumen blended with light hydrocarbons and/or synthetic crude oil

Source: NEB Estimates

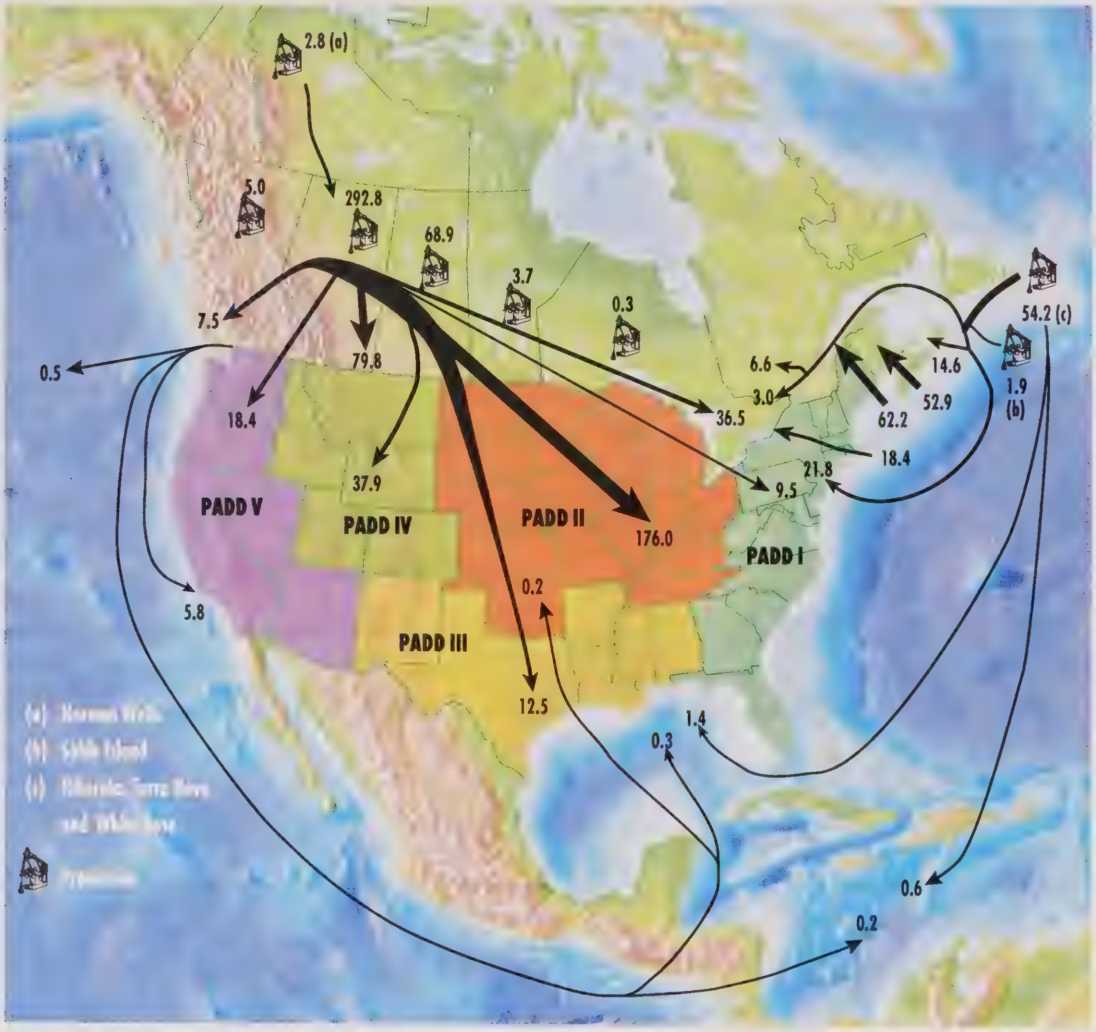
11 Canada accounted for 20 per cent of U.S. imports, Saudi Arabia accounted for 16 per cent and Mexico accounted for 12 per cent.

Although Canada is a net crude oil exporter, imports account for a significant portion of Canadian refinery demand. Refineries located in Ontario, Quebec and Atlantic Canada source a portion of their crude oil from abroad, while western Canadian refineries are fully supplied by domestic production.

In 2008, crude oil imports are estimated to be 133 000 m³/d (840 Mb/d). This is a decrease of approximately 2.3 per cent compared with 2007 and represents 47 per cent of total Canadian refinery feedstock. OPEC countries supplied 59 per cent of imports and 34 per cent was delivered from the North Sea. The remaining seven per cent was sourced from our NAFTA partners (U.S. and Mexico) and other countries. An estimated 78 per cent of the Atlantic refining requirements were met by imports and the remaining 22 per cent with eastern Canadian production. Quebec remained the largest regional importer of crude oil with 90 per cent of its refining needs supplied from international sources. Ontario accounted for the remainder of imported crude volumes. Ontario refineries are increasingly sourcing crude oil supplies from western Canada.

FIGURE 4.7

Crude Oil Supply and Disposition – 2008 (thousand cubic metres per day)



4.5 Oil Refining

There were 19 Canadian refineries operating at the end of 2008 with a total refinery capacity (distillation) of 335 000 m³/d (2.1 MMb/d), up from 325 000 m³/d (2.0 MMb/d) in 2007. The refineries and their locations are included in Table 4.4.

Canadian demand for petroleum products in 2008 is estimated to be 264 000 m³/d (1.7 MMb/d), roughly the same as 2007. The lack of growth reflects slumping demand because of very high prices during the summer and reduced economic activity in the third and fourth quarters of 2008. Refinery runs of crude oil in Canada in 2008 are estimated to be 284 000 m³/d (1.8 MMb/d), a decline of two per cent over 2007 levels of 290 000 m³/d (1.8 MMb/d). Refinery capacity utilization also decreased from 90 per cent in 2007 to 88 per cent in 2008. Refinery receipts of domestic crude oil declined by 6.2 per cent in 2008 to 148 000 m³/d (935 Mb/d), largely because of the reduction in refinery runs due to the price driven decline in demand for petroleum products during the summer. Spring and summer refinery outages and maintenance activity in western Canada resulted in gasoline and diesel fuel shortages, as well as reduced crude oil usage at those facilities.

TABLE 4.4

Refineries in Canada

Company	Location	Capacity (m^3/d)	Capacity (b/d)
Atlantic Canada		**76 600**	**482 600**
Imperial Oil Limited	Dartmouth, N.S.	13 000	81 900
Irving Oil Limited	Saint John, N.B.	45 300	285 400
North Atlantic Refining (Harvest Energy)	Come-by-Chance, Nfld.	18 300	115 300
Quebec		**83 500**	**526 000**
Petro-Canada	Montreal	20 700	130 400
Shell Canada Limited	Montreal	20 700	130 400
Ultramar Limited	St. Romuald	42 100	265 200
Ontario		**74 800**	**471 200**
Imperial Oil Limited	Nanticoke	17 800	112 100
Imperial Oil Limited	Sarnia	19 200	121 000
Shell Canada Limited	Sarnia	11 400	71 800
NOVA Chemicals	Sarnia	13 200	83 200
Suncor Energy Products Inc.	Sarnia	13 200	83 200
Western Canada		**99 800**	**628 900**
Consumers Co-operative Refineries Ltd.	Regina, Sask.	15 600	98 300
Husky Energy Marketing Inc.	Lloydminster, Alta.	4 000	25 200
Imperial Oil Limited	Strathcona, Alta.	29 700	187 100
Moose Jaw Asphalt	Moose Jaw, Sask.	2 500	15 800
Petro-Canada	Edmonton, Alta.	21 900	138 000
Shell Canada Limited	Scotford, Alta.	15 900	100 200
Chevron Canada Limited	Burnaby, B.C.	8 300	52 300
Husky Energy Marketing Inc.	Prince George, B.C.	1 900	12 000
Total		**334 700**	**2 109 000**

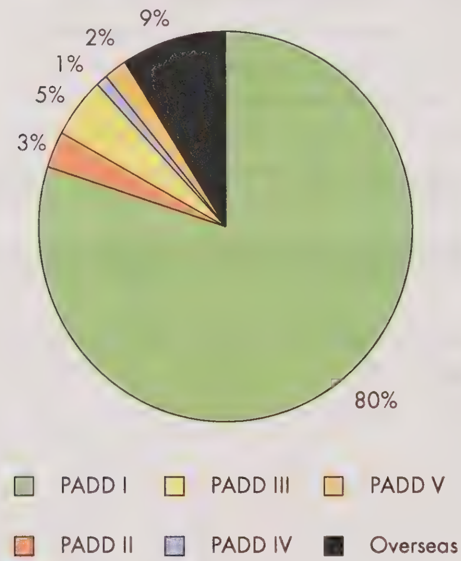
Source: NEB

4.6 Main Petroleum Product Exports and Imports

Canada continued to be a net exporter of petroleum products, with the U.S. as its principal customer. Exports of main petroleum products in 2008 are estimated to be 52 540 m^3/d (331 Mb/d), a marginal increase from 2007. Exports were primarily destined for the U.S. east coast market (PADD I) with overseas exports being the second largest market. Figure 4.8 illustrates the destination for main petroleum product exports.

FIGURE 4.8

Product Exports by Destination – 2008



Source: NEB (Data available to October 2008)

The estimated revenue in 2008 from exports of main petroleum products, including partially processed oil, was \$11 billion, up from about \$9 billion in 2007. Very high crude oil prices supported by tight markets in the first half of 2008 were key drivers behind the jump in revenues. A strong global distillate market kept diesel prices high throughout the year and distillate production was critical to keeping refineries profitable. Stagnant gasoline demand and rising crude oil prices had a negative effect on gasoline margins in the first half of 2008.

Canadian imports, primarily from the U.S., were up by 25 per cent on a year-on-year basis. This increase reflects the drop in Canadian production caused in part by unplanned refinery outages. Year-on-year growth in domestic sales of petroleum products was negligible meaning that while product balances and consumption remained the same, production setbacks were off-set by higher imports.

4.7 Product Prices

According to Natural Resources Canada (NRCan)[12], average Canadian retail product prices were approximately 23 per cent higher in 2008 compared with 2007, reflecting increases in world crude oil prices. Retail gasoline prices in Canada increased from 102 cents/litre in 2007 to 114 cents/litre in 2008 (Table 4.5). Because of a tight global distillate market, diesel and furnace oil prices increased at a greater rate than gasoline. 2008 prices for diesel and furnace oil averaged 125 cents/litre and 113 cents/litre, respectively, which is an average increase of 29 per cent from 2007.

TABLE 4.5

World Oil and Canadian Products Prices

Product	2008 (cents/litre)	2007 (cents/litre)	Change	Change (%)
Gasoline	114.0	101.8	+12.2	12.0
Diesel	124.9	99.8	+25.1	25.2
Furnace oil	113.2	85.7	+27.5	32.1
WTI (US\$/bbl, Cushing, OK)	99.67	72.34	+27.3	37.8
Edmonton Par (Cdn\$/bbl)	102.87	76.97	+25.9	33.6

Source: NRCan, EIA, NEB

World crude oil prices were volatile in 2008 and product price movements typically respond to crude oil prices; however, gasoline prices were

12 Natural Resources Canada, *Fuel Focus, 2008 Annual Review*, 11 January 2009.

softened by stagnant demand and did not rise in direct proportion to the rise in crude oil prices. This negatively affected the profitability of refineries. A combination of tight global supply–demand and volatile crude oil prices caused diesel prices to rise rapidly. Refineries geared production, as much as possible, to maximize distillate (diesel) output. Refinery and upgrader problems in Alberta at times caused pro-rationing of both gasoline and diesel, further tightening the situation and increasing prices in western Canada. The demand reduction experienced in the second half of 2008, however, caused year-end inventories of both gasoline and distillate to exceed 2007 levels.

4.8 Looking Ahead

Crude oil prices reached unprecedented levels in the summer of 2008 but had declined substantially by year-end in response to the global economic downturn. In order to stimulate their economies, central banks around the world have cut interest rates and governments have announced major stimulus spending packages. 2009 is expected to be a difficult year for the global economy and this, in turn, will result in reduced crude oil demand. Accordingly, forecasters are predicting low crude oil prices for 2009 reflecting poor GDP growth in developed countries and slower growth in developing countries such as China and India. Because of the low crude oil price environment anticipated in 2009, Canada can expect lower crude oil export revenues.

Continued volatility and uncertainty will be a challenge for both consumers and producers in the coming year. Given the challenging global economic conditions, numerous capital investment projects have been deferred or cancelled. These projects were primarily aimed at increasing production and refining capacity. In Canada, the list of cancelled or deferred projects is growing and until the price of crude oil rebounds to a level that provides economic incentive for investment, incremental production volumes and refining capacity will remain in doubt.

Increasing links between the environment, energy and the economy will continue to be part of the Canadian dialogue in 2009. How this will impact the Canadian oil industry remains uncertain; however, a shift in policy in major consuming regions around the globe could spur technological advancements which in turn would allow for cleaner, more sustainable growth. In this context, Canada, with its large endowment of natural resources and growing importance in the global energy picture, will be well positioned to seize opportunities to achieve sustainable energy development.

Natural Gas

5.1 North American Natural Gas Markets

In 2008, about one-quarter of the natural gas produced in North America came from Canada. About 97 per cent of Canadian gas continues to be produced from the WCSB with Alberta producing roughly 78 per cent. British Columbia and Saskatchewan contribute approximately 16 and four per cent, respectively, of total WCSB production. Daily production from the WCSB remained steady through the first three quarters of the year at 445 $10^6m^3/d$ (15.7 Bcf/d) before rapidly declining in the fourth quarter to 428 $10^6m^3/d$ (15.1 Bcf/d) as early cold winter weather caused freezeoffs at the wellhead.

Together, the Canadian and U.S. natural gas markets operate as one large integrated market. This means that events in any one region such as changes in transportation costs, infrastructure constraints or weather will affect the other regions. The majority of Canadian and U.S. natural gas production continues to come from areas roughly following the continental divide, from the Gulf of Mexico to the Northwest Territories. New production has tended to come from unconventional sources, especially shale gas, whose development expanded rapidly in Canada during 2008. Demand is spread across the continent but is concentrated in densely populated areas and in areas of intense industrial activity. North American demand declined in 2008 primarily as a result of decreased industrial demand brought on by the economic downturn. Canadian gas production is connected to the North American gas market through a network of thousands of kilometres of pipeline that allows buyers to purchase and transport natural gas from a number of supply sources across the continent.

Natural gas prices have been volatile in recent years and this volatility continued in 2008 (Figure 5.1). New highs were reached early in July before the economic downturn decreased demand at the same time that new domestic supply was coming on stream. Those two factors combined to drop the price to less than $6.00/MMBtu in the last part of 2008. Additionally, the price of natural gas is particularly sensitive to real and anticipated weather events and this can result in large seasonal swings. A lack of spare productive capacity in North America resulted in tight market conditions that have contributed to high and volatile natural gas prices since 2001. However, growing production from shale and other unconventional gas resources in North America has helped to offset the ongoing decline in conventional production, easing the tight supply–demand balance and contributing to the decline in gas prices in the second half of 2008.

Natural gas prices can also be sensitive to crude oil prices; however, in 2008 this price relationship became increasingly disconnected as gas prices were well below oil on an energy equivalent basis. Some consumers can switch between natural gas and fuel oil for their heating needs, particularly in the U.S. northeast and southeast. This competition provides a link, albeit imperfect, between oil prices and natural gas prices, such that an increase in crude oil prices can support an increase in the price of natural gas. The rapid fall in oil prices and the global financial crisis in the second half of 2008 had a significant impact on natural gas prices this year. Natural gas prices in North America, as measured by the three-day average at the Henry Hub, rose to a high of around $13/MMBtu in

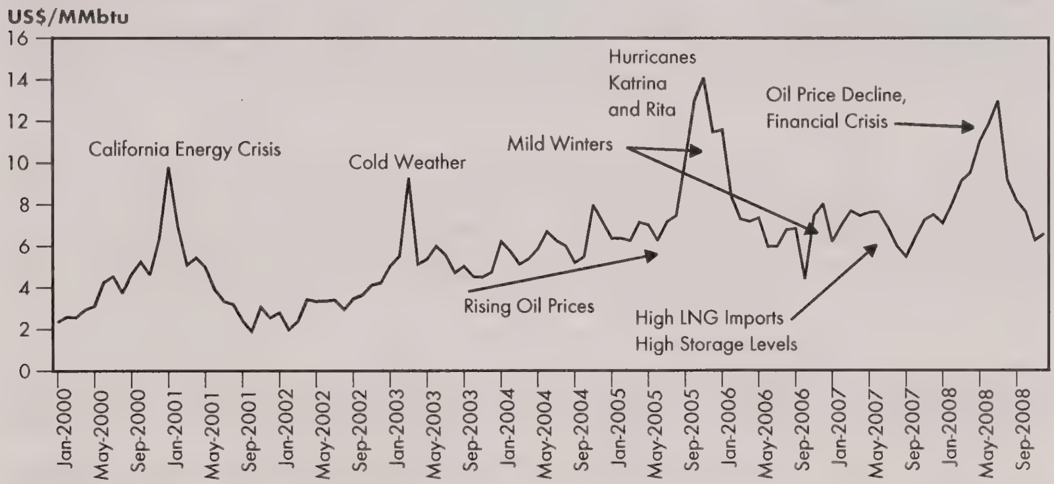
July 2008 and subsequently fell by about 50 per cent by the end of the year. Natural gas prices for 2008 averaged US$9/MMBtu, almost 30 per cent higher than 2007.

Natural gas is produced at a relatively steady rate throughout the year whereas its consumption is seasonal. To balance supply with demand, gas is injected into underground storage in the summer and withdrawn in the winter months. April is the beginning of the typical storage injection season (Figure 5.2). Temperatures in early 2008 were very cold throughout the U.S. northeast and eastern Canada. With these being large consuming regions, a previous storage surplus was depleted. Storage levels began the injection season below 2007 levels and below the five-year average. However, in 2008, storage levels steadily grew to the end of October, almost reaching the record high of 2007 before entering the 2008–2009 winter heating season in November.

U.S. gas production increased significantly in 2008, offsetting reductions in LNG imports (which were less than half of the levels reached in 2007) and Canadian gas production. Considerably milder

FIGURE 5.1

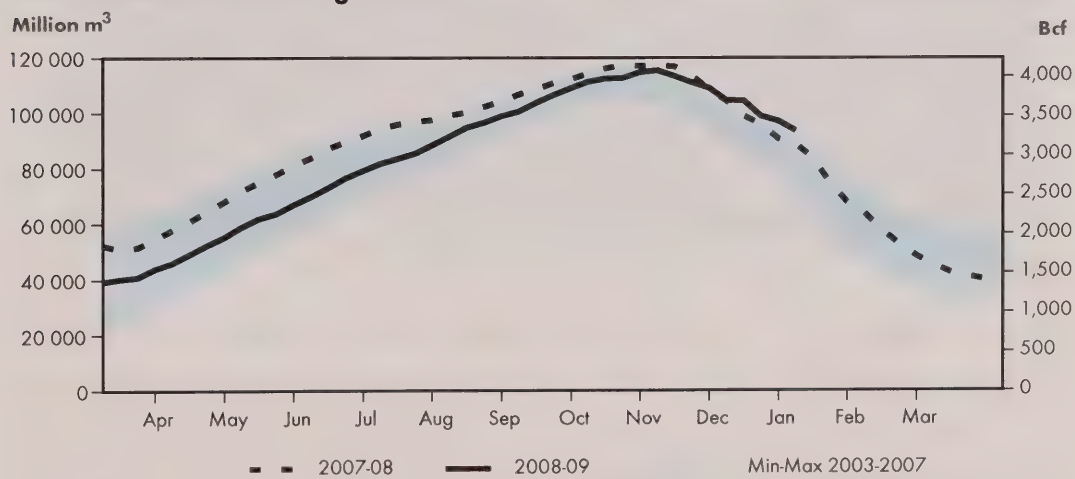
North American Gas Price Trends – Henry Hub (Monthly average)



Source: GLJ Publications Inc.

FIGURE 5.2

North American Gas Storage Levels



Source: Canadian Enerdata Ltd., NEB estimates, U.S. Energy Information Administration

temperatures in the summer and fall, compared to 2007, allowed for steady injections into storage in 2008.

Western Canadian natural gas prices, measured at the AECO hub in Alberta, which is located near a number of natural gas storage fields near the southern border of Alberta and Saskatchewan, began 2007 at \$6.57/GJ and reached an all-time mid-summer high of \$11.22/GJ in July and a pre-heating season low of \$5.50/GJ in September before closing the year at \$6.07/GJ, following the trend of the U.S. Henry Hub price (Figure 5.3). Although prices in 2005 reached higher levels than 2008 because of hurricane supply disruptions, the average price of 2008 was, overall, five per cent higher than the 2005 average.

Prices in eastern Canadian markets are cited at the Dawn Hub, which is located near underground storage facilities in southwestern Ontario, and include a component of transportation and storage costs. The Dawn price began the year at US\$8.05/MMBtu and reached a high of US\$13.63/MMBtu in early July (Figure 5.4). Similar to the AECO price, the Dawn price, in Ontario, declined through

FIGURE 5.3

Daily AECO-C Price

Source: Platts

FIGURE 5.4

Daily Dawn Price

Source: Platts

the fall and early winter of 2008 to close the year at US$6.20/MMBtu. Falling commodity prices, including natural gas, contributed to the decline in the Canadian dollar in the second half of 2008. However, Canadian natural gas prices remained well-connected to North American gas prices overall.

5.2 North American Natural Gas Supply

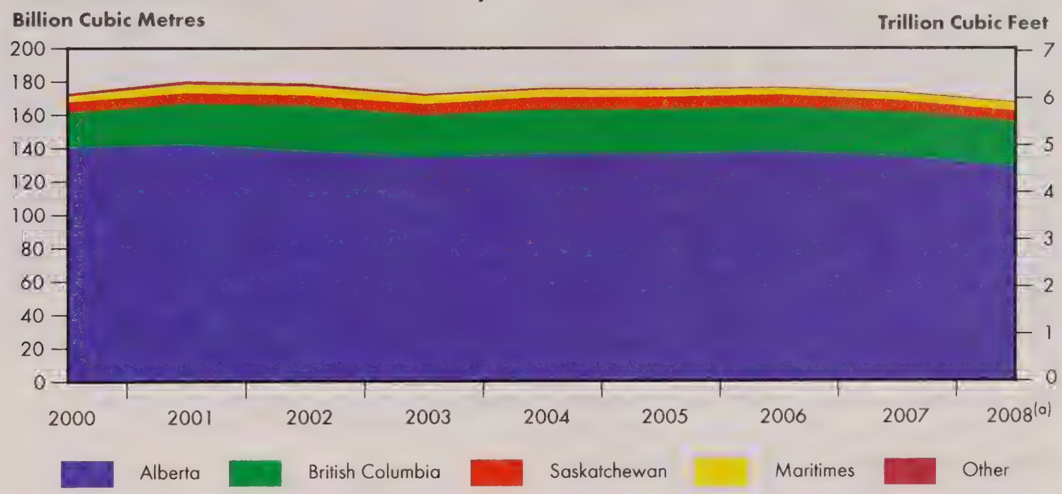
2008 Canadian natural gas production averaged 458 million m^3/d (16.2 Bcf/d), ranking Canada behind the U.S. and Russia as the world's third largest gas producer, the same position Canada has had since 1982. 2008 production was roughly four per cent or 18 million m^3/d (0.65 Bcf/d) less than in 2007 (Figure 5.5). Alberta led the decline with production falling five per cent from 2007 levels. The only regions to show increases in 2008 were British Columbia and the Maritimes, whose production rose by one and seven per cent from 2007, respectively. The overall Canadian production decline since 2006 can be linked to a pullback in drilling activity in western Canada which started that year.

In 2008 there was recognition of and significant public attention drawn toward large potential shale gas resources in several areas of Canada, including Quebec, Alberta and British Columbia (Figure 5.6). While positive exploration results were released in those areas, only the Montney Formation of British Columbia has been under development and producing significant amounts of shale gas over the past few years, approximately 8.5 million m^3/d (300 MMcf/d) by year-end 2008, 62 per cent higher than 2007 production. Shale gas from the Horn River Basin of British Columbia was producing around 1.4 million m^3/d (50 MMcf/d), all of it added during 2008.

There remains significant resource potential in coalbed methane (CBM) even though industry has focused its efforts on Canadian shale gas. Production of CBM in 2008 averaged approximately 21.4 million m^3/d (757 MMcf/d)[13], an 11 per cent increase over 2007. However, CBM development outside of the WCSB still faces challenges. In 2008, Shell Canada voluntarily imposed a drilling moratorium in the Klappan area of northwestern British Columbia over the concern of residents about the footprint of oil and gas operations. Since then, the British Columbia government has

FIGURE 5.5

Canadian Marketable Gas Production, 2000 – 2008



(a) Estimate

Source: Provincial and territorial regulatory agencies

13 CBM production is sometimes mingled with other shallow non-coal formations with no method to differentiate the source of production, therefore CBM production reported here is likely overestimated to a small extent.

imposed a two-year moratorium on CBM activity in the Klappan area. Consultations continue between industry, government and community groups.

On the east coast, Sable production averaged 11.7 million m^3/d (400 MMcf/d) or about four per cent less than 2007 production. Production from the onshore McCully field in New Brunswick has remained stable at about six per cent of the region's production or 0.8 million m^3/d (26.6 MMcf/d).

In 2008, hurricanes Gustav and Ike each shut in almost 200 million m^3/d (7.0 Bcf/d) in the Gulf of Mexico; by year-end, approximately 42 million m^3/d (1.5 Bcf/d) was still shut in[14]. Despite this, U.S. dry gas production, which averaged 1.5 billion m^3/d (52.3 Bcf/d) in 2007, grew to 1.6 billion m^3/d (56.2 Bcf/d) in 2008, an astonishing 7.5 per cent increase, mainly from growth in the Barnett, Fayetteville and Haynesville shale gas plays of Texas, Louisiana and Arkansas (Figure 5.5) and tight sands in Texas and the Rocky Mountain basins. This supply glut has been a substantial factor in the

FIGURE 5.6

Major Shale Gas Prospects in North America

Developing: Barnett, Fayetteville, Haynesville, Woodford, Marcellus, Montney and Horn River.
Evaluating: Barnett/Woodford, Utica and Gothic.
New Shale Plays: Growth in Medium to Long Term.

Source: Modified from Ziff Energy Group

Note: The triangles attached to the red lines represent mountain fronts, where the triangles point in the direction of land mass that has been overridden by the mountains (i.e. a thrust fault).

14 EIA, *Impact of the 2008 Hurricanes on the Natural Gas Industry*, 2009.

Unconventional Natural Gas in Canada

As additional reserves of conventional natural gas become increasingly difficult to find in mature areas like the WCSB, exploration companies have been shifting their focus to a wide variety of unconventional resources. These are generally found in widespread, low permeability deposits (permeability is defined as the ability of a fluid to move through a porous and/or fractured solid). These unconventional resources require special drilling and hydraulic fracturing techniques as well as an increased number of wells drilled per unit area.

Two types of shallow unconventional resources are shallow gas and CBM, which are normally only exploited when less than one kilometre deep and through closely spaced vertical wells, although CBM wells may be drilled horizontally. Shallow gas originates from muddy sandstones and has been exploited in the region near Medicine Hat, Alberta for more than 100 years. CBM is natural gas produced from within coal cleats (i.e. fractures in the coal). While water is produced from some coals, others are dry and produce no water. For example, the Horseshoe Canyon Formation coals of central Alberta are by far the largest producer of CBM in Canada and produce almost no water. Rates from individual wells in these shallow resources tend to be low, around 1 500 m^3/d (0.05 MMcf/d), but may last for several decades. Recently, producers have also stepped out into some sandy shales for shallow shale gas production.

Two types of deep unconventional resources are tight gas and shale gas, normally found around two kilometres in depth or deeper. Tight gas consists of low permeability conglomerates and sandstones (for example, the Cadomin Formation of west-central Alberta and northeast British Columbia) or limestones and dolostones (for example, the Jean Marie Formation of northeast British Columbia). Shale gas comes from organic rich mudstones where some of the organic material has been converted to methane. An example of this is found in northeast British Columbia in the Horn River Basin.

A hybrid between tight gas and shale gas is a sandy mudstone called the Montney Formation, found in northeast British Columbia and west-central Alberta. After horizontal drilling and hydraulic fracturing, these tight gas and shale gas reservoirs typically produce from 30 000 m^3/d (1.1 MMcf/d) to 350 000 m^3/d (12.3 MMcf/d) before declining to around 8 000 m^3/d (0.3 MMcf/d) for ten years or more.

significant drop in natural gas prices and the subsequent decrease in drilling across the continent, including Canada.

LNG import capacity into the U.S. increased substantially in 2008 through the addition of two new terminals and the expansion of existing facilities. At the end of 2008, import capacity into the U.S. was over 300 million m^3/d (10 Bcf/d), from eight terminals. Despite this capacity increase, U.S. LNG imports averaged only 27 million m^3/d (1.0 Bcf/d), less than half of the average level of LNG imported in 2007 (60 million m^3/d or 2.1 Bcf/d). The drop in LNG imports in 2008 reflects the higher demand and prices received for LNG in other global markets during the year. Those markets attract supplies away from the U.S. Canada's first LNG facility was under construction throughout 2008 and is expected to become operational in 2009. This facility will primarily import natural gas as LNG and ship the regasified natural gas to the New England market.

5.3 Natural Gas Reserves

Despite Canada's number three ranking in terms of natural gas production, Canada ranks 21st in the world in terms of reserves, defined as the total amount of marketable gas in discovered pools that can be extracted in current economic conditions. The NEB's estimate of remaining marketable gas reserves at the end of 2007 is 1 607 billion m^3 (56.3 Tcf) (Table 5.1). Reserve additions were 139 billion m^3 (4.9 Tcf) in 2007 and replaced only 78 per cent of annual production. The decrease

TABLE 5.1

Canadian Natural Gas Reserves

(10^9m^3) At Year-end 2007	Natural Gas Reserves		
	Initial Reserves	Cumulative Production	Remaining Established Reserves
British Columbia	940.1	545.9	394.2
Alberta	4 893.3	3 823.9	1 069.3
Saskatchewan	271.0	181.8	89.2
Subtotal – WCSB	**6 104.4**	**4 551.6**	**1 552.7**
Ontario	54.3	34.3	20.0
Nova Scotia Offshore	55.0	34.1	20.9
Mainland NWT & Yukon	29.1	16.1	13.0
Mackenzie Delta	0.3	0.1	0.2
Subtotal – Frontier	**84.4**	**50.3**	**34.1**
Total Canada	**6 243.1**	**4 636.2**	**1 606.8**
Total Canada (Tcf)	**220.4**	**163.7**	**56.3**

Sources: Various regulatory and industry bodies.

in remaining reserves reflects the pullback in drilling by exploration companies from 2005 highs. Initial reserves, the cumulative total of reserves discovered in Canada up to year-end 2007 with no subtractions for production, increased in Alberta, British Columbia and Saskatchewan, while frontier regions and Ontario remained largely unchanged.

5.4 Canadian Natural Gas Consumption

Approximately one-quarter of all energy consumed by Canadians is natural gas. This amounts to an estimated consumption in 2008 of about 216 million m^3/d (7.6 Bcf/d), or about 47 per cent of Canadian production. Canada ranks among the top five natural gas consuming nations, accounting for about three per cent of world consumption.

Canadian Natural Gas Reserves – How Much Gas is There?

Canada is the third largest natural gas producer in the world behind Russia and the U.S. However, Canada is 21st in terms of reserves. While remaining established reserves are reduced by production each year, new discoveries, extensions to existing pools and revisions to reserves estimates usually add to reserves. As a result, the changes in reserves annually from production are generally much less than the annual production volume.

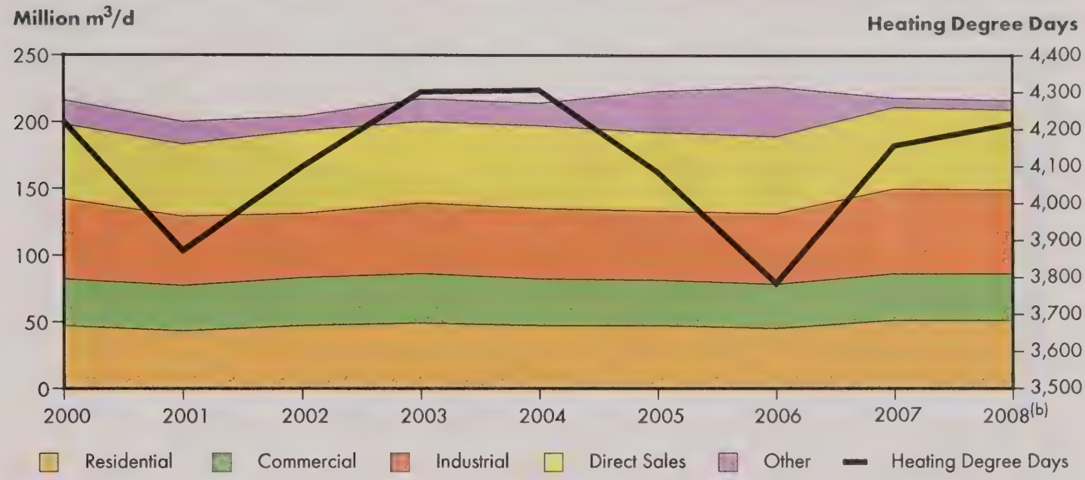
Currently, if these additions are not considered, our reserves life is one of the lowest in the world at 9.1 years, meaning it would take only 9.1 years to exhaust our proven reserves at the current production rate. But, if experience is any indicator, Canada will not run out of natural gas any time soon. The U.S. has maintained a 10-year reserve life for the past 25 years, lately through reserve additions of shale gas, which Canada is just beginning to exploit.

Natural gas is primarily consumed in the residential and commercial sectors for space heating, in the industrial sector for process heat, as a building block in chemical production, and to produce electricity. Canadian gas demand for heating, industrial use and electric power generation (included within "direct sales") has been fairly flat since 2000 (Figure 5.7).

Despite continuing growth in residential and commercial floor

FIGURE 5.7

Canadian Total Gas Consumption and Heating Degree Days[a]



(a) Heating degree day (HDD) is an index calculated to reflect the demand for energy needed for heating homes, businesses, etc. HDD are the cumulative number of degrees in a year for which the mean temperature falls below 18.3°C.

(b) Estimate

Source: Statistics Canada, NEB Estimates, and Canadian Gas Association

space, actual natural gas consumption in this sector has changed little since 2000, growing by approximately 0.7 per cent annually on average. This is attributed, at least in part, to mild winter weather over the past few years. Four of the past eight years rank among Canada's top 10 warmest years[15]. 2008 was slightly colder than the previous year, but still 0.7 Celsius above normal, according to Environment Canada. Besides weather effects, higher and more volatile natural gas prices moderated natural gas consumption, particularly in the price-sensitive industrial sectors, in recent years.

The most significant impact on natural gas consumption was the emergence of major economic turmoil in the global financial markets seen in 2008. The economic recession in the U.S. has resulted in lower industrial activity, collapsing commodity prices and tight credit conditions. Canadian manufacturing and industrial sectors have been impacted by these recessionary forces and gas consumption in these sectors was estimated to have declined by three per cent in 2008.

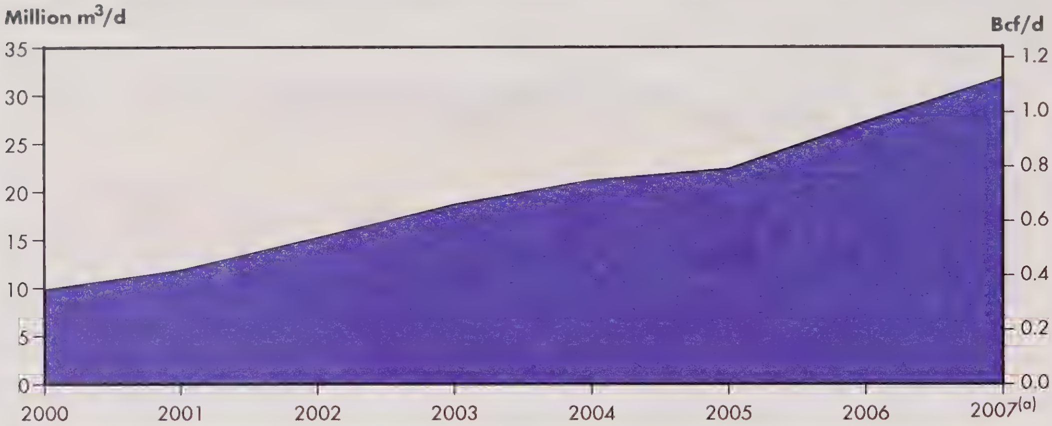
Natural gas is used in both the generation of electricity and steam. Steam is used for in situ oil production and in the production of hydrogen to upgrade bitumen into synthetic crude oil blends. A fast-growing sector for natural gas consumption over the past few years has been the Alberta oil sands (Figure 5.8). Consumption of natural gas in 2008 was almost 30 million m³/d (1.1 Bcf/d) – over three times the amount of gas used in 2000. While upgrader production declined by two per cent in the latter half, compared to 2007 levels, in situ production had increased overall in 2008.

Although the oil sands industry is a large natural gas user, efforts are underway to reduce its dependence on this fuel. This includes pursuing energy efficiency improvements as well as the adoption of alternative fuels and technologies, such as bitumen gasification, which will provide the bulk of fuel requirements and feedstock in the OPTI/Nexen Long Lake SAGD/Upgrader project, which began production operations in late 2008.

15 Environment Canada, *Climate Trends and Variations Bulletin, Annual 2008*, 19 January 2009.

FIGURE 5.8

Average Annual Natural Gas Requirements for Oil Sands Operations



(a) Estimate

Source: NEB and ERCB

In the longer term, it is expected that the application of bitumen gasification will gradually gain momentum in both in situ and upgrading operations if it can be shown to be an economic alternative to natural gas. As well, improvements and modifications to SAGD methods, and the application of other technologies such as toe-to-heel air injection (THAI™) will begin to play a larger role. THAI™ combustion technology for in situ bitumen recovery combines a vertical air injection well (toe), with a horizontal production well (heel). Most of the heat required to mobilize the bitumen is derived from the combustion process within the reservoir, thus reducing the need for natural gas compared with other thermal recovery methods. Therefore, although natural gas demand in oil sands applications is expected to increase, it will not increase at the same rate as oil sands production.

5.5 Canadian Natural Gas Exports and Imports

2008 natural gas exports were about 282 million m^3/d (10 Bcf/d) or 16 per cent of estimated U.S. consumption. The U.S. Central/Midwest and the U.S. Northeast regions are Canada's largest export markets. Overall, exports of natural gas to the U.S. were lower in most months of 2008 than in 2007 (Figure 5.9). Although the U.S. National Climatic Data Center reported that in 2008 the U.S. experienced its coolest year in more than 10 years[16], economic weakness and growing U.S. natural gas production in 2008 reduced the requirement for Canadian gas imports.

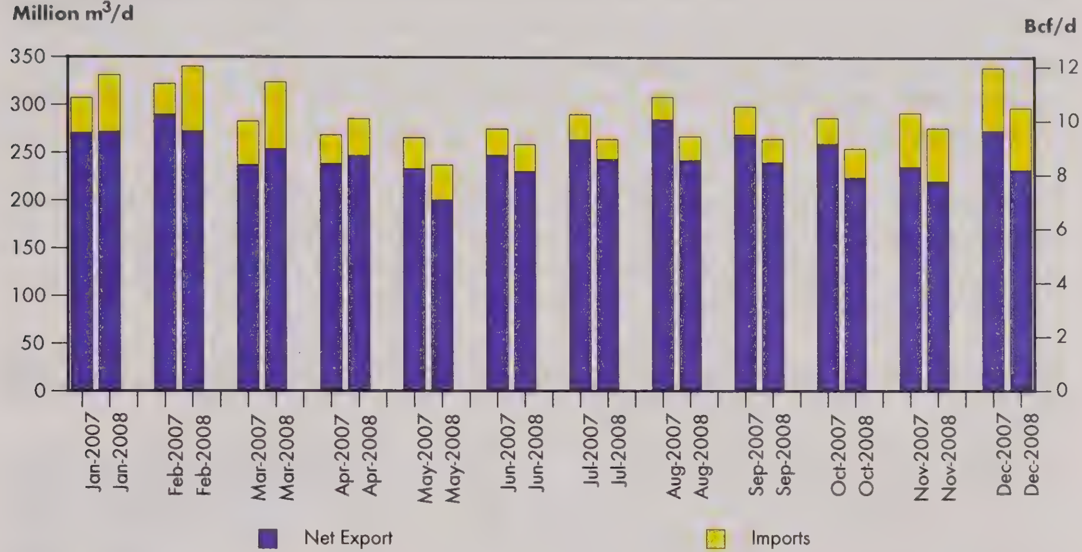
The gross volume of Canadian gas exported to the U.S. was four per cent lower compared with 2007. Net exports (gross exports less imports) for 2008 were 239 million m^3/d (8.4 Bcf/d), about eight per cent lower than the 2007 net export volume of 258 million m^3/d (9.1 Bcf/d).

Canadian revenues from gas exports increased significantly in 2008 over 2007. Although there was a decrease in export volumes, the average export price was about 20 per cent higher in 2008 than in 2007 because of extremely high prices in the first half of 2008. This resulted in net export revenues of about $28 billion, 15 per cent higher than in 2007. 2009 average natural gas prices are not expected to be as high as the 2008 average price. With lower expected Canadian gas requirements in the U.S., because of both lower economic activity and growing U.S. production, the Board, therefore, does not expect 2009 net export revenues to increase from 2008.

16 2008 Annual Climate Review U.S. Summary, National Climatic Data Center, 20 January 2009.

FIGURE 5.9

Monthly Natural Gas Export and Import Volumes



Source: NEB

Pipeline infrastructure allows gas to flow along a choice of pipeline options when destined to eastern markets. As a result, natural gas may be imported through import points in Ontario, if it is economic. Although Canada is a net exporter of natural gas, an estimated 44 million m^3/d (1.5 Bcf/d) of gas was imported into Ontario from the U.S. in 2008 (Figure 5.10).

5.6 Natural Gas Liquids (excluding Pentanes Plus)

NGLs are light hydrocarbons produced from natural gas as liquids through an extraction process in gas processing plants or as a by-product of crude oil refining and upgrading. Natural gas liquids, for the purpose of discussion here, include ethane, propane and butanes. Natural gasoline, also known as pentanes plus or condensate, is discussed in Section 4.

Propane and butane prices climbed during the first half of 2008, buoyed by skyrocketing oil prices and petrochemical demand in North America. However, during the second half of the year, propane and butanes prices followed the free fall of crude prices. Propane price at Mont Belvieu, the main NGL trading hub in the United States, fell from an historical monthly average record of 169.3 U.S. cents per gallon in August 2008 to 69.5 U.S. cents per gallon in December.

Canadian propane production in 2008 is projected to be 31 300 m^3/d (197.2 Mb/d), a decrease of 0.8 per cent over 2007 production. Propane from gas plants in 2008 is estimated to be 27 694 m^3/d (174.5 Mb/d), slightly lower (-0.2 per cent) than last year. Estimated propane production from refineries declined 5.7 per cent to 3 516 m^3/d (22.2 Mb/d) as a consequence of lower refinery runs compared with 2007.

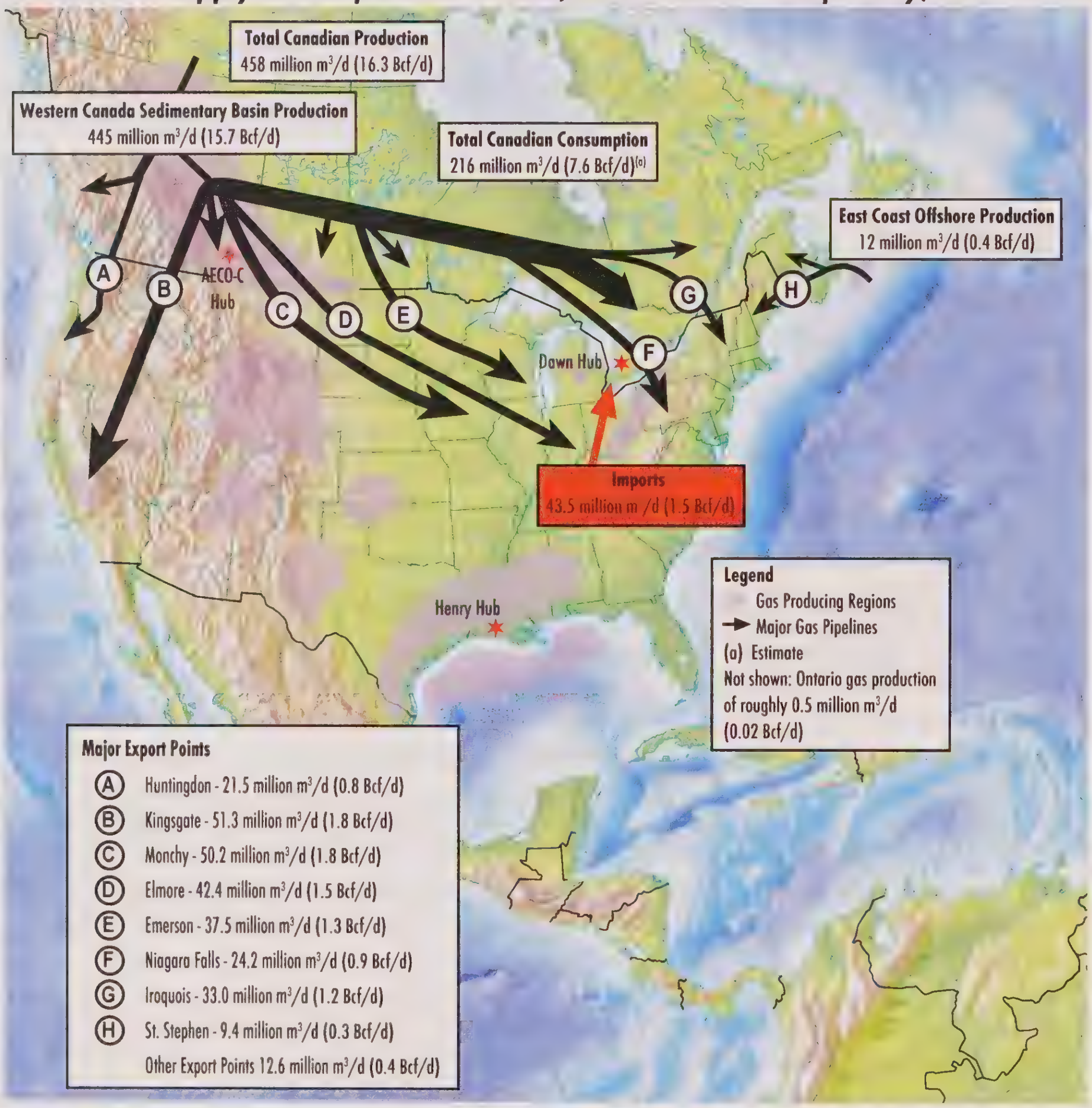
2008 ethane production from gas plants is estimated to be 37 969 m^3/d (239.2 Mb/d), a 0.9 per cent reduction as the economic downturn in the United States depressed demand for petrochemical feedstocks. Butane production in Canada in 2008 is projected to be 24 974 m^3/d (157.3 Mb/d), an increase of 1.9 per cent over 2007 figures. Refinery production of butane is estimated to be 8 003 m^3/d (50.4 Mb/d), while butanes from gas plants is estimated to be 16 050 m^3/d (101.1 Mb/d), an increase of 6.7 per cent and 1.6 per cent respectively over the previous year.

Exports of propane in 2008 are estimated to be 17 663 m³/d (111.3 Mb/d), declining five per cent from 2007. Butane exports in 2008 were 4 164 m³/d (26.2 Mb/d), an increase of 9.1 per cent over last year. PADD II (Midwest) was the most important destination for propane and butane exports with 57.8 per cent and 54.4 per cent of total exports of each product, followed by the U.S. east coast (PADD I) with 23.9 per cent and 31.6 per cent, respectively. The decrease in propane exports is associated with lower propane production and higher domestic demand, while the increase in butane exports is mostly related to higher production and lower Canadian demand for refinery feedstock.

Even though propane export volumes were lower in 2008, record propane prices helped to increase the estimated export revenue for the year by 17.1 per cent to $2.7 billion. Butane export revenues were also up 35.5 per cent to $748 million, supported by record prices and higher export volumes. Export revenue for the two commodities totaled almost $3.4 billion.

FIGURE 5.10

Natural Gas Supply and Disposition – 2008 (million cubic metres per day)



5.7 Looking Ahead

Shale Gas

With the prevalence of shale deposits throughout North America (Figure 5.6), there has been much optimism and an increase in recent industry activity to pursue potential development of similar resources in Canada. Today, efforts are ongoing to assess shale gas prospects in northeast British Columbia (Horn River Basin and the Montney Formation), southern Alberta and Saskatchewan (Colorado shale), Quebec (Utica shale), and Atlantic Canada (Windsor Group shales). Each shale is in various stages of development or experimentation. There was significant growth in Montney shale gas production in 2008, along with the first production from Horn River Basin shales. While growth is expected to continue into 2009 as shale gas continues to attract industry attention even in the recent downturn, growth is not expected to be as dramatic as that seen in 2008.

While having significant potential, the full extent of commercial development of shale resources is still uncertain. The near-term contribution of Canadian shale development may also be constrained by the need to assess viability, optimize operations and build the necessary connecting infrastructure to access major pipelines. Other considerations include the environment because of high water usage in shale gas operations. Furthermore, Horn River Basin shale gas is 12 per cent CO_2 and its production has the potential to significantly increase Canadian CO_2 emissions unless the CO_2 is re-injected. Local operators are planning for sequestration of the CO_2 into porous formations several kilometres below the surface.

Finally, should Canadian shale gas become a reliable, long-term supply for the North America energy mix, it could become used much more extensively as a substitute for oil and coal in an effort to reduce GHG emissions and to improve energy security.

Liquefied Natural Gas

Global LNG trade enables the development and movement of significant natural gas resources around the world to supplement domestic production. Proven reserves of natural gas worldwide are about 20 times larger than the proven natural gas reserves of North America. Despite being the world's largest producer of natural gas, North America has historically used LNG imports to supplement its indigenous production and provide an important option to ensure that reliable and secure gas supplies are available.

Although the current economic downturn and lower and volatile energy prices will likely reduce the demand for natural gas and the requirement for new LNG import terminals in North America, the long-term requirement for energy and natural gas is still projected to grow. Greater production from shale and other unconventional gas resources have also helped to offset the ongoing decline in conventional production and may reduce or set back the immediate requirement for LNG imports.

In the longer term, economic recovery and environmental initiatives to reduce the combustion of other fossil fuels and GHG emissions may result in significant demand for natural gas and LNG. The extent to which North America pursues various alternate energy sources to natural gas will greatly influence the overall need for LNG. The Board recently published an Energy Market Assessment on the dynamics of global natural gas and LNG markets, the likelihood and availability of future LNG imports to North America and the potential implications for Canadian natural gas markets and LNG development[17].

17 NEB, *Liquefied Natural Gas – "A Canadian Perspective"*, 2008.

In anticipation of growing natural gas requirements in North America, there are numerous proposals to expand existing terminals in the U.S. and Mexico and construct new LNG receiving facilities. Given the integrated nature of the North American natural gas market and infrastructure, Canadian import LNG terminals will likely serve markets in both Canada and the U.S. The extent to which North American LNG facilities will be used and whether long-term supply is available will be determined largely by competitive factors such as market conditions and the stakeholders involved, including their respective contractual arrangements for supply and markets and the requirement for LNG in other global regions.

The first Canadian LNG import terminal (Canaport LNG in Saint John, New Brunswick) is expected to become operational in mid-2009. With prospects for significant future production from shale gas development, and potentially lower requirements for gas exports to the U.S., there are now two proposals to develop an LNG export terminal at Kitimat, British Columbia The eventual number of LNG projects to be developed in Canada is not certain. In general, proposed and existing Canadian LNG projects are located competitively with other North American and global terminals.

ELECTRICITY

6.1 Regional Initiatives

Electricity industry activity during 2008 included new infrastructure and also many efforts to maintain adequate supply and reliable operation. Initiatives included new infrastructure additions and also many institutional and governmental initiatives, announcements and clean energy programs across the country.

Western Canada

BC Hydro announced it would pursue a Bioenergy Call to independent power producers to utilize forest-based biomass, including sawmill residue and logging debris. The utility also launched a Standing Offer Program for renewable generation projects up to 10 MW and launched the Clean Power Call for large renewable projects, with the intent of acquiring up to 5 000 GW.h annually.

The Alberta government introduced a regulation aimed at promoting the development of micro-generation. Customers in Alberta can now run their own small-scale "environmentally friendly" generation projects and receive credit for any power they supply to the grid, in excess of their own needs. The micro-generation units must be less than one MW in size and employ a renewable technology, such as wind, solar, biomass or small-scale hydro.

SaskPower announced that it will pursue a demonstration CCS project at its Boundary Dam coal facility. The project will be pursued as a

SaskPower's Boundary Dam Carbon Capture and Storage Demonstration Project

Saskatchewan's public electric utility, SaskPower, has partnered with the Government of Canada, the Government of Saskatchewan and private industry to fund and develop a CCS demonstration project at SaskPower's Boundary Dam coal-fired generating station, near Estevan, Saskatchewan.

The project is expected to cost $1.4 billion and involves the refurbishment of Boundary Dam Unit #3, originally built in 1960 and otherwise scheduled for retirement in 2013, and retrofitting post combustion carbon capture technology, thereby extending the plant life by as much as 30 years.

The project is to be undertaken in two phases. Phase 1, scheduled for 2011 to 2013, would result in emissions from Unit #3 being reduced to levels comparable to a conventional natural gas combined cycle plant and a reduction in the net-to-grid output of Unit #3 from 139 MW to 120 MW. Phase 2 of the project, from 2013 to 2015, would further reduce the plant output to 100 MW and reduce emissions to near zero, capturing nearly one million tonnes of CO_2 annually. A process is currently underway to select a vendor for the CCS technology.

Once captured, the CO_2 would be compressed into liquid form and shipped via pipeline to nearby oilfields where it would be injected into oil reservoirs. Injection of CO_2 into oil reservoirs allows more oil to be extracted (enhanced oil recovery) and serves as permanent storage for the liquefied CO_2. Securing a buyer for the captured CO_2 and developing the pipeline transmission infrastructure from Boundary Dam to the oilfields will be critical to the success of the project.

Ontario's Smart Meters

Ontario is introducing smart meters – along with a "time-of-use" electricity price structure – to help customers manage their electricity costs, while helping Ontario to build a more efficient and environmentally sound electricity system. So far in Ontario, more than two million smart meters have been installed – almost half the target number. Every home and small business should have a smart meter installed by 2010.

A smart meter can record and report electricity consumption information automatically. In Ontario, smart meters will record electricity consumption on an hourly basis and, typically, report that information via wireless technology.

Electricity prices paid by consumers can vary during different hours of the day, which reflects the way prices are established in the electricity market. This will encourage consumers to think more about how and when they use electricity. As they move consumption away from the more expensive (peak) times of the day, consumers can help Ontario reduce its peak demand, which can help limit the construction and operation of peak-generating facilities.

Smart meters – plus time-of-use rates – will provide customers with a cost-management tool.

government and industry partnership to rebuild and retrofit the existing Boundary Dam Unit #3 with carbon capture technology. This project will demonstrate the technical, environmental and economic benefits of CCS.

Manitoba Hydro continued to expand its Power Smart programs in 2008, particularly with the introduction of new biomass electric production incentives. This program will assist users with potential to utilize biomass for distributed generation by providing feasibility assessment and generation construction services.

Ontario and Quebec

Ontario set the stage during 2008 for renewable energy developers to bid on 500 more MW of new green energy supply. The final contract rules have been set for a competition to award new contracts for projects larger than 10 MW. This bidding will mark the first phase of a Renewable Energy Supply procurement process, one that is intended to combat climate change by adding 2 000 MW of new green power to Ontario's electricity supply.

Hydro-Québec's goal of saving eight TW.h of electricity by 2015 has been increased to saving 11 TW.h, or about six per cent of annual customers' forecasted consumption. The target of 4.3 TW.h in 2010 is now established at five TW.h. If Quebec reaches its savings by 2015, it would be equivalent to saving the annual consumption of about 550,000 houses in the province.

Atlantic Canada

In 2008, the New Brunswick government initiated an analysis of the province's current electricity market. The final report will consider the structure of the electricity market and its impact on the structure and governance of the NB Power group of companies. New Brunswick also released a preliminary report exploring various models for developing community wind energy, as well as the province's *Strategic Environmental Assessment Report on In-Stream Tidal Energy Generation*. The report suggests that tidal energy generation could become a reality on New Brunswick shores of the Bay of Fundy.

The P.E.I government released a three-part Environment and Energy Policy Series entitled *Securing Our Future*. The first volume sets out a ten-point plan on how to meet the goal of growing wind to 500 MW by 2013, as well as to explore issues pertaining to the intermittency of wind power and how to back up this volume of wind capacity. The second volume explores biofuels and biomass and sets out a provincial energy strategy and vision, while the third volume speaks to climate change and

global warming. As the province imports nearly 85 per cent of its energy needs, which are primarily petroleum based, the P.E.I. strategy targets diminishing dependence on imported oil.

6.2 Electricity Prices

Canadian electricity prices are determined in regional markets. Prices in most jurisdictions are based on the cost of providing service to consumers including a regulated rate of return on generation, transmission and distribution assets. Costs are approved by provincial and, in some cases, municipal regulators. When required, the cost of new generation, usually higher than costs of "heritage assets," must also be approved and rolled in, resulting in higher average costs. This model is followed in all provinces and the territories except Alberta, where generation costs are based on competitive wholesale markets. Ontario is a hybrid of the two methodologies, with a blend of heritage pricing for coal, nuclear and hydro plants and market-based prices for new generation.

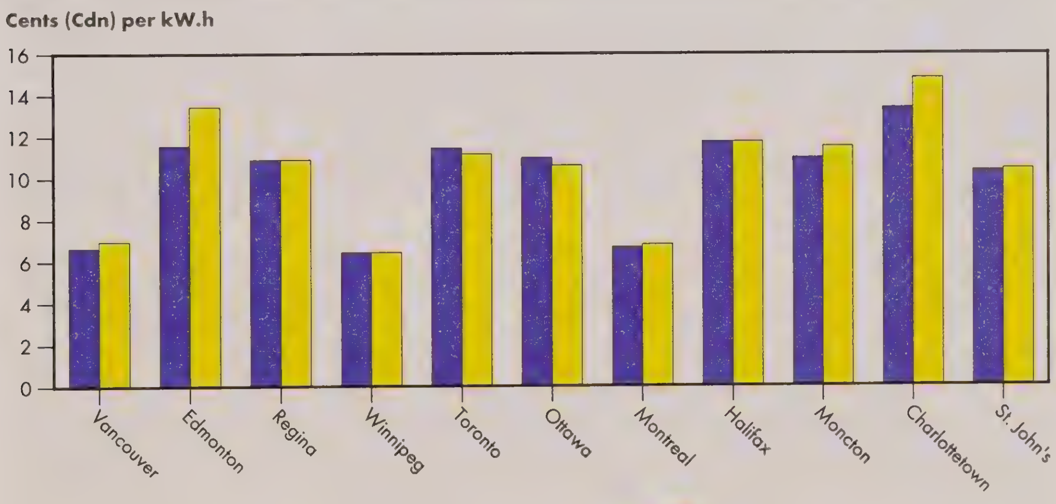
Prices tend to be lowest in hydro-based provinces such as British Columbia, Manitoba and Quebec, which benefit from a high proportion of low-cost heritage assets, such as hydro-generating facilities that have minimal fuel costs and largely amortized capital costs. Electricity prices are most volatile in Canadian jurisdictions that rely on fossil fuels for generation and are increasing most in Canadian jurisdictions that require costly new generation and transmission.

Figure 6.1 charts the year-over-year average cost of electricity for a typical household in various Canadian cities based on rates in effect as of 1 April. Prices in Charlottetown and Edmonton increased significantly, while prices in Ontario cities decreased.

The cost of electricity for residents in P.E.I. is based largely on a fixed energy rate and a variable Energy Cost Adjustment Mechanism (ECAM). The ECAM adds to the overall cost when fossil fuel prices are high, and because such fuels were more expensive in the spring of 2008 than a year earlier, the prices in P.E.I. increased year-over-year.

FIGURE 6.1

Canadian Residential Electricity Prices
(Based on 1 April rates and consumption level of 1 000 kW.h per month)



Source: Hydro-Québec: Comparison of Electricity Prices in Major North American Cities

Residents in Alberta have the option to pay either a competitive contract rate or the default Regulated Rate Option (RRO) which is set monthly. Every year until 2010, the RRO will be based more on the next-month projected cost of electricity and less on the long-term projection. The difference in the RRO from April 2007 to April 2008 represents most of the increase shown for Edmonton prices.

Residents in Ontario also have the option to pay either a contract rate or pay according to the Regulated Price Plan (RPP) which is set annually. The RPP is based on a forecast of wholesale prices and generation from regulated facilities. The RPP prices in effect for most of 2008 were lower than the previous year, which explains the decrease shown for Toronto and Ottawa prices. However, the wholesale prices averaged slightly higher, and the RPP prices were raised as of November 2008.

6.3 Electric Reliability

The reliability of the Bulk Power System (BPS) is achieved through ensuring that supply adequacy and operating reliability is maintained in generation and transmission. Operation of the BPS within the requirements of a set of reliability standards is critical to ensuring that the BPS can operate reliably despite power system disturbances and contingencies.

Reliability standards developed by the North American Electric Reliability Corporation (NERC) and/or by NERC's regional reliability organizations are mandatory in the U.S. In Canada, the individual provinces are adopting either the NERC standards or compatible standards. For instance, NERC standards were adopted through legislation in British Columbia and Alberta and are mandatory in Ontario and New Brunswick through the market rules governing transmission in those provinces. NERC standards are applicable in Saskatchewan and Manitoba through contractual agreements with the Midwest Reliability Organization (NERC's regional reliability organization). In Quebec, reliability standards are developed by TransÉnergie and approved by la Régie de l'énergie, the provincial energy regulator.

In April 2008, the NEB issued letters to international power line (IPL) owners that the Board is pursuing the option of amending the National Energy Board Electricity Regulations to implement mandatory reliability standards on IPLs. The Board is exploring different possibilities for amending the regulations while recognizing regional interests.

A main driver for the implementation of mandatory reliability standards was the major power blackout that affected Ontario and the U.S. northeast in August 2003. While there is currently no single measure to indicate trends in overall electric reliability, NERC continues to work toward developing such measures. For example, the number of power system disturbances has shown a declining trend since 2003. It is NERC's view that the development of mandatory standards and the increased attention paid to reliability by the BPS operators have resulted in improved reliability in recent years.

6.4 Electricity Generation

Canadian generation decreased from 607 TW.h to 601 TW.h in 2008 (Table 6.1). Hydroelectric generation increased from 366 TW.h to 369 TW.h, the result of favourable conditions in hydroelectric-generating provinces. Thermal generation decreased from 150 TW.h in 2007 to 139 TW.h, reflecting the economic slowdown and higher fuel prices. Nuclear generation was stable overall as Ontario generation offset impacts of plant outage in New Brunswick. Wind generation increased by more than 20 per cent to 3.6 TW.h.

TABLE 6.1

Electricity Production (TW.h)

	2004	2005	2006	2007	2008
Hydroelectric	336.7	358.4	349.5	365.8	369.3
Nuclear	85.2	86.8	92.4	88.2	88.6
Thermal	154.6	157.3	147.7	149.6	139.1
Wind & Tidal	1.0	1.6	2.5	2.9	3.6
Total	**577.5**	**604.2**	**592.0**	**606.5**	**600.6**

Note: Wind generation for 2008 estimated based on CanWEA data.

Source: 2001 to 2007: Statistics Canada 57-202
2008: CanWEA, Statistics Canada 127-0002

Many forms of generation, including conventional and emerging technologies (e.g., wind, small hydro and biomass) were proposed across the country in 2008. Some significant regional power generation developments follow.

SaskPower pursued the addition of two 94 MW simple cycle gas-fired peaking generation plants in 2010 to meet the increased load driven by population and economic growth in the province. Natural gas turbines are also viewed as a "green" replacement technology, especially for jurisdictions currently dealing with oil and standard coal electricity generation plans.

Going Green: Evolving Electricity Generation

Canadians are increasingly interested in the impact of energy and our environment. More and more, one cannot be mentioned without the other in mind. While Canadians increasingly feel more personal responsibility for their environment, change happens slowly. The development of green energy options answers Canadian environmental concerns, such as air quality and global warming.

Electric generation is one area in which emerging technologies, including wind power, small hydro, biomass, geothermal energy, fuel cells, solar cells, ocean energy and clean coal increasingly pose significant potential for cleaner, greener energy. Implementing new technology, while promoting local economic growth and protecting the environment does not come without its challenges. Collectively referred to as "renewables", greener options include:

Wind Power: *A commercially viable source of power, wind involves no fuel cost, emissions or waste. However, wind does not always blow and most wind farms operated at between 25 to 35 per cent capacity.*

Biomass: *Landfill gas and waste products are used to create electricity, reducing greenhouse gases. However, high start-up and operating costs pose a challenge.*

Small Hydro: *This well established technology is Canada's largest contributor to "going green". With low capital costs and many possible sites available in Canada, small hydro poses a much smaller environmental impact than larger hydro options. However, small hydro can be costly and time consuming given associated regulatory approvals, and local opposition to development can delay the growth of this technology.*

Other emerging technologies, including solar, geothermal and wave power continue to evolve.

Construction of the Wuskwatim Generating Station in Manitoba progressed last year with the completion of the first phase of excavation and a transmission line. This project represents the first collaboration in Canada for construction and ownership of a large hydroelectric generation facility between a First Nations group and a public utility.

In Ontario, two major gas-fired generators came online in high value locations (Sarnia and Toronto), with a combined output near 1 500 MW. These facilities will form part of the capacity needed to phase out coal-fired generators in the province. Coal-fired electricity generation dropped to a level unseen in the last decade, whereas wind and gas-fired generation continued to rise in both installed capacity and energy output.

In Quebec, commissioning of the Chute-Allard and Rapides-des-Cœurs hydro developments began in 2008. The two generating stations will have a total capacity of 139 MW and full operation is expected in mid-2009. The Péribonka 385-MW generating facility has also been completed in 2008 and will add about 2.2 TW.h of clean energy annually. Hydro-Québec decided to refurbish its Gentilly-2 nuclear power plant in Bécancour. The project is scheduled for late 2010 to mid-2012 at a cost of $1.9 billion. Refurbishing the 675-MW plant will extend its operation until 2040 and provides about 5.0 TW.h of low emissions annual output.

In New Brunswick, NB Power is currently refurbishing the Point Lepreau nuclear reactor. It was taken out of service in March 2008 and it is scheduled to be back in service in late 2009 or early 2010. The Point Lepreau generating station provides up to 30 per cent of New Brunswick's electricity and is one of the lowest cost generators on NB Power's electrical system. Studies of the potential for a second nuclear reactor at Point Lepreau have also reached the conclusion that a merchant model is viable under certain conditions, including long-term market commitments. A second reactor would have the potential to displace oil in New Brunswick and P.E.I., as well as coal in Nova Scotia.

Wind

According to the Canadian Wind Energy Association (CanWEA), total wind generation capacity was about 2 370 MW at the end of 2008, enough to power over 680,000 homes or equivalent to about one per cent of Canada's total electricity demand. Canada's wind generating capacity rose 34 per cent from 2007, ranking 16th in the world. It has officially become the 12th country in the world to surpass 2 000 MW.

At the end of 2008, Ontario was the leader in wind power in Canada with 782 MW of installed capacity, followed by Quebec and Alberta with 532 MW and 524 MW, respectively (Figure 6.2).

6.5 Electricity Demand

Over the past few years, electricity demand growth in Canada has shown some signs of moderating, partly from conservation and improved efficiency and partly because of slowing economic activity in some industrial sectors. In 2008, initial estimates indicated demand declined from 576 TW.h in 2007 to 568 TW.h (Table 6.2).

Demand growth trends varied across the country. As a result of increased conservation efforts and slowing industrial demand, British Columbia's electricity consumption dropped two per cent from the 2007 levels. Alberta consumption continued to grow, requiring increased imports from British Columbia and Saskatchewan. Consumption in Saskatchewan stayed on par with 2007. The five per

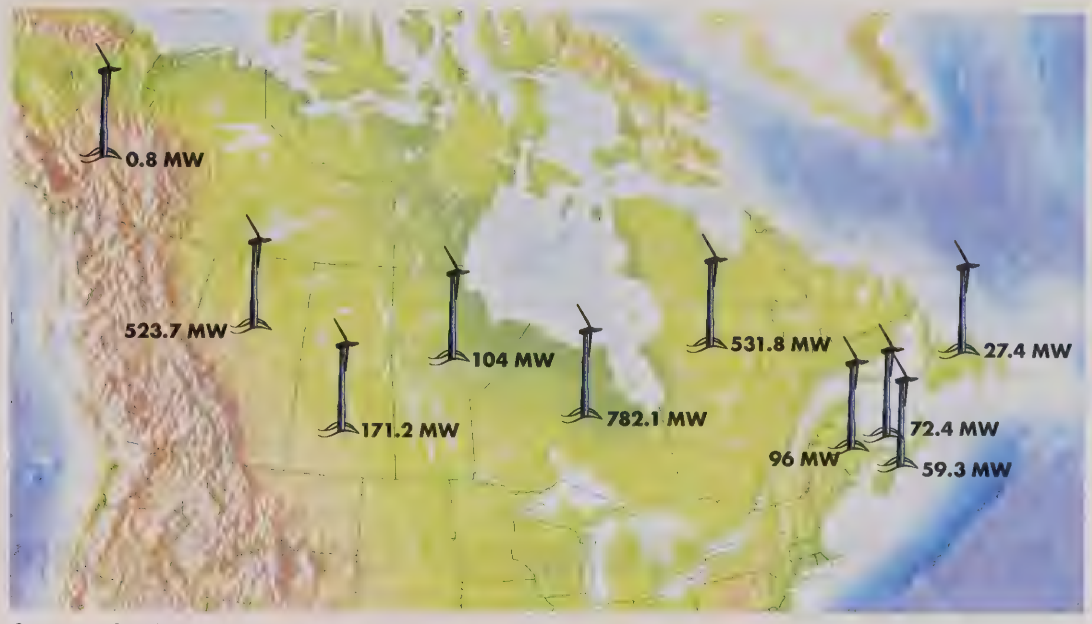
cent growth in Manitoba led the nation in 2008. To meet the increased demand, Manitoba generated three per cent more electricity and exported six per cent less than in 2007.

In contrast, the economic slowdown contributed to a decline in demand of three per cent in Ontario and two per cent in Quebec. Despite this softening in demand, generation (and exports) in these provinces increased significantly.

In the eastern provinces, any concern about supply adequacy has been reduced by an economic slowdown that has reduced overall demand. The manufacturing industry has been hit hard by the slowdown and, as plants have shut down, demand has decreased. The refurbishment of Point Lepreau contributed to a 16 per cent drop in New Brunswick generation and significantly more imported electricity. Newfoundland and Labrador reported increased consumption in 2008.

FIGURE 6.2

Canadian Wind Farms



Source: CanWEA

TABLE 6.2

Electricity Generation and Disposition (TW.h)

	2004	2005	2006	2007	2008
Supply					
Total Generation	577.5	604.2	592.0	606.5	600.6
Imports	22.2	18.7	22.1	18.4	23.5
Total Supply	**599.7**	**622.8**	**614.1**	**625.0**	**624.1**
Disposition					
Demand	566.9	580.5	574.3	575.6	568.4
Exports	32.8	42.3	39.7	49.3	55.7
Total Disposition	**599.7**	**622.8**	**614.1**	**625.0**	**624.1**

Source: 2001 to 2007: Statistics Canada 57-202, NEB
2008: CanWEA, Statistics Canada 127-0003, NEB

Trends in the Territories varied. Indications are that in 2008, consumption decreased by three per cent in Yukon, remained relatively constant in the Northwest Territories, and increased by four per cent in Nunavut.

6.6 Electricity Exports and Imports

Electricity exports increased 13 per cent from 49 TW.h in 2007 to 56 TW.h and were 40 per cent above the previous five-year average of 39 TW.h. Imports increased from 18 TW.h to 24 TW.h in 2008. Imports were about 10 per cent above the previous five-year average of 21 TW.h. Canada exported approximately $3.8 billion of electricity compared to $3.1 billion in 2007, an increase of 22 per cent.

Canadian electricity jurisdictions tend to be winter-peaking systems and so the largest imports of electricity from the U.S. typically occur during the winter when local heating requirements are highest.

Net exports increased by four per cent from 31 TW.h in 2007 to 32 TW.h. Net exports were nearly double the previous five-year average of 18 TW.h. Figure 6.3 illustrates international and interprovincial transfers of electricity.

The overall increase in exports and export revenues can be attributed to favourable water conditions in hydroelectric-generating provinces and export growth in Ontario. Exports from Quebec increased from 2007 levels, while exports from British Columbia and Manitoba dropped slightly. For the first time in decades, Ontario exported the most electricity, with exports amounting to 125 per cent more than the previous five-year average. Imports into Ontario increased as well, whereas Quebec and Manitoba imported significantly less than in 2007. For the sixth consecutive year, British Columbia's trade balance alternated between net exports and net imports, as the province reported net exports of 3.1 TW.h in 2007 and net imports of 3.4 TW.h in 2008.

FIGURE 6.3

International and Interprovincial Transfers of Electricity – 2008[a] (GW.h)

6.7 Looking Ahead

In planning for adequacy of future supplies, utilities and their regulators are paying particular attention to renewables, conservation and efficiency improvement.

A number of wind projects are already under construction that will be fully commissioned soon. As a result, despite the poor economic outlook, 2009 installations could exceed those completed in 2008. Accordingly, Canada could pass the 3 000 MW mark for wind capacity in 2009. Integration of new wind capacity into the grid will continue to pose challenges across the country. Fortunately, Canada's large hydroelectric resources, which account for about 60 per cent of Canada's electricity, provide a complement for fluctuating wind generation, enabling the opportunity to integrate more wind energy into the system. This is an advantage Canada has over other countries in the development of the wind power.

Canadian electricity consumers face upward pressure on electricity rates, mainly driven by the development of higher-cost sources of generation. Volatile fuel prices including natural gas, oil and coal will also impact generation costs and therefore, electricity prices. Consumer prices will be generally more stable in the hydro-based provinces and where prices are established on a cost-of-service basis.

Export revenues will continue to be dominated by hydroelectric-generating provinces. Despite decreasing levels anticipated in the foreseeable future in reaction to the economic slowdown, electricity exports are expected to continue to be a significant source of revenue. Imports will provide reliability for those provinces interconnected with adjacent U.S. regions.

Jurisdictions are expected to continue initiatives toward improving interconnections both inter-provincially and internationally. One such project is the Canada to Northern California project. The Canadian portion of the line is expected to run from the Selkirk substation in southwestern British Columbia to northern Oregon, where it will connect northern California. The line is being spearheaded by California's PG&E and is designed to access incremental renewable resources in the U.S. Pacific Northwest as well as Canadian electricity.

Conclusion

The Canadian energy economy demonstrated strong growth in 2008. Despite small decreases in the production of hydrocarbons, export revenues were higher. At the same time, governments across Canada placed greater importance on environmental protection and made progress in key areas such as CCS and on policies to lower GHG emissions. Canadian conventional oil and oil sands development continued and is increasingly being seen as a critical piece of the North American energy security picture. The natural gas industry, in the midst of change, is finding new supply sources that will have an important, yet uncertain, impact in the market. Electricity generation in Canada is becoming greener.

Canada, with its vast natural resources and diverse economy, is well positioned to responsibly face current challenges and seize opportunities to be recognized as an energy leader. Energy, the environment and the economy will remain interconnected, and Canada will continue on its journey toward sustainable development of energy resources.

AECO or AECO-C	Alberta gas trading spot price.
Bitumen or crude bitumen	A highly viscous mixture, mainly hydrocarbons heavier than pentanes. In its natural state, it is not usually recoverable at a commercial rate through a well because it is too thick to flow.
Coalbed methane	Is a form of natural gas extracted from coalbeds. Coalbed methane, often referred to as CBM, is distinct from a typical sandstone or other conventional gas reservoir, as the methane is stored within the coal by a process called adsorption.
Conventional crude oil	Crude oil, which at a particular point in time, can be technically and economically produced through a well using normal production practices and without altering the natural viscous state of the oil.
Conventional gas	Refers to natural gas from all sources other than CBM.
Hub	A geographic location where large numbers of buyers and sellers trade a commodity and where physical receipts and deliveries occur.
In situ recovery	The process of recovering crude bitumen from oil sands other than by surface mining.
Marketable gas	Natural gas that has been processed to remove impurities and natural gas liquids. It is ready for market use.
Natural gas liquids	Those hydrocarbon components recovered from natural gas as liquids. These liquids include, but are not limited to, ethane, propane, butanes and pentanes plus.
Oil sands	Sand and other rock material that contains bitumen. Each particle of oil sand is coated with a layer of water and a thin film of bitumen.
Pentanes plus	A mixture mainly of pentanes and heavier hydrocarbons obtained from the processing of raw gas, condensate or crude oil.
Reserves – Established	The sum of the proven reserves and half probable reserves.
Reserves – Initial Established	Established reserves prior to deduction of any production.
Reserves – Proven	Reserves recoverable under current technology and present and anticipated economic conditions, specifically demonstrated by drill, testing or production.
Reserves – Remaining	Initial reserves less cumulative production at a given time.


National Energy Board | Office national de l'énergie

Canadian Energy Overview 2009

AN ENERGY MARKET ASSESSMENT JUNE 2010

Canada

National Energy Board

Office national de l'énergie

Canadian Energy Overview 2009

AN ENERGY MARKET ASSESSMENT JUNE 2010

Canada

Cat. No. NE2-4/2009E
ISBN 978-1-100-16043-6

This report is published separately in both official languages. This publication is available upon request in multiple formats.

Copies are available on request from:
The Publications Office
National Energy Board
444 Seventh Avenue S.W.
Calgary, Alberta, T2P 0X8
E-mail: publications@neb-one.gc.ca
Fax: 403-292-5576
Phone: 403-299-3562
1-800-899-1265
Internet: www.neb-one.gc.ca

For pick up at the NEB office:
Library
Ground Floor

Printed in Canada

N° de cat. NE2-4/2009F
ISBN 978-1-100-94848-5

Ce rapport est publié séparément dans les deux langues officielles. On peut obtenir cette publication sur supports multiples, sur demande.

Demandes d'exemplaires :
Bureau des publications
Office national de l'énergie
444, Septième Avenue S.-O.
Calgary (Alberta) T2P 0X8
Courriel : publications@neb-one.gc.ca
Télécopieur : 403-292-5576
Téléphone : 403-299-3562
1-800-899-1265
Internet : www.neb-one.gc.ca

Des exemplaires sont également disponibles à la bibliothèque de l'Office :
Rez-de-chaussée

Imprimé au Canada

TABLE OF CONTENTS

FIGURES

TABLES

BPS	Bulk Power System
CanWEA	Canadian Wind Energy Association
CBM	Coalbed Methane
CCS	Carbon Capture and Storage
CO_2	Carbon Dioxide
EIA	Energy Information Administration
EMA	Energy Market Assessment
ERCB	Energy Resources Conservation Board
FIT	Feed in Tariff
GDP	Gross Domestic Product
GEA	Green Energy Act (Ontario)
GHG	Greenhouse Gas
IEA	International Energy Agency
LNG	Liquefied Natural Gas
MOU	Memorandum of Understanding
NEB or Board	National Energy Board
NERC	North American Electric Reliability Corporation
NGLs	Natural Gas Liquids
NRCan	Natural Resources Canada
NSB	North Sea Brent
OECD	Organization for Economic Co-operation and Development
OPEC	Organization for Petroleum Exporting Countries
PADD	Petroleum Administration for Defense District
RES	Renewable Energy Standards
RRO	Regulated Rate Option
SAGD	Steam Assisted Gravity Drainage
WCSB	Western Canada Sedimentary Basin
WTI	West Texas Intermediate

LIST OF UNITS

b/d	Barrels per day
bbl	Barrel
Bcf/d	Billion cubic feet per day
BTU	British thermal unit
$	Canadian dollars
GJ	Gigajoule
GW.h	Gigawatt hour
kW.h	Kilowatt hours
m^3/d	Cubic metres per day
Mb/d	Thousand barrels per day
MMb/d	Million barrels per day
MMbtu	Million British thermal units
MMcf/d	Million cubic feet per day
Mt	Megatonne
MW	Megawatt
MW.h	Megawatt hour
PJ	Petajoules
US$	U.S. dollars
Tcf	Trillion cubic feet
TW.h	Terawatt hour

Foreword

The National Energy Board (NEB or the Board) is an independent federal agency that regulates several aspects of Canada's energy industry. Its purpose is to regulate pipelines, energy development and trade in the Canadian public interest[1] within the mandate set by Parliament. The NEB is active and effective in Canada's pursuit of a sustainable energy future.

The Board's main responsibilities include regulating the construction and operation of interprovincial and international oil and gas pipelines as well as international and designated interprovincial power lines. The NEB takes a lifecycle approach to all phases of a regulated facility including the application assessment and public hearing phase, the construction and post-construction phase, the operations and maintenance phase, and the abandonment phase.

For pipelines under its jurisdiction, tolls and tariffs are subject to Board regulation. The Board regulates the exports and imports of natural gas as well as exports of oil, natural gas liquids (NGLs) and electricity. The Board also regulates oil and gas exploration, development and production in frontier lands and offshore areas not covered by provincial or federal management agreements. The Board's advisory function requires it to keep under review matters over which Parliament has jurisdiction relating to all aspects of supply, transmission and demand for Canadian energy.

The NEB monitors energy markets to objectively analyze energy commodities and inform Canadians about trends, events and issues. Annually, the Board conducts a review of the previous year's energy markets in an Energy Market Assessment, entitled *Canadian Energy Overview*. This year's report, *Canadian Energy Overview 2009* is a summary of major developments related to energy in Canada in 2009.

If a party wishes to rely on material from this report in any regulatory proceeding before the NEB, it may submit the material, just as it may submit any public document. Under these circumstances, the submitting party in effect adopts the material and that party could be required to answer questions pertaining to the material.

This report does not provide an indication about whether any particular application will be approved or not. The Board will decide on specific applications based on the material in evidence before it at that time.

1 The public interest is inclusive of all Canadians and refers to a balance of economic, environmental and social issues that changes as society's values and preferences evolve over time. The Board weighs the relevant impacts of these interests when making its decisions.

EXECUTIVE SUMMARY

The year 2009 clearly demonstrated the interrelationship between energy demand and supply and economic conditions in Canada. Along with the overall economic downturn, energy production and consumption declined, as did the employment in, and output of, the Canadian energy industry. Energy prices remained relatively low at the start of the year, continuing to be impacted by the financial crisis that plunged the global economy into a recession in the second half of 2008.

While global economic conditions captured much of the attention in 2009, many citizens remained concerned about energy and the environment. One of the biggest stories in energy and the environment for 2009 occurred at the UN Climate Change Conference. The conference took place in Copenhagen, Denmark in December and resulted in a non-binding agreement, the Copenhagen Accord. In Canada, the federal government announced a new emissions reduction target for Canada, 17 per cent below 2005 levels by 2020.

2009 was a recession[2] year, with Canada's gross domestic product (GDP) declining 2.5 per cent. The energy industry directly accounted for an estimated 6.7 per cent of Canadian GDP in 2009, down slightly from 2008. Energy is one of Canada's largest exports, and in 2009 it represented 23 per cent of the country's total exports. On average, energy prices were lower in 2009, resulting in a drop in energy export revenues to $81 billion from a record high level of $133 billion in 2008.

Oil export volumes increased while oil export revenues declined from 2008 because of lower crude oil prices. The continuing decline in conventional production in western Canada, and maintenance and natural pool decline on the east coast, offset oil sands production increases. Lower crude oil prices in the first half of 2009 resulted in the deferral or cancellation of many new oil sands projects lowering growth projections, as well as the shut-in of some production. Reductions in production by OPEC resulted in a narrower light-heavy crude oil price differential that benefited heavy crude oil and bitumen producers. Due to oil price recovery in the second half of 2009, and signs of global economic recovery, shut-in volumes and a number of deferred projects were reinstated.

Natural gas drilling activity in Canada was at its lowest level of the past decade in 2009 and consequently, natural gas production continued its decline. Canadian exports declined slightly because U.S. requirements were increasingly met by growing U.S. production, particularly from shale gas sources, and increased liquefied natural gas (LNG) imports. Natural gas export revenue dropped significantly because of the combined impact of lower gas prices and lower export volumes. Shale gas production in Canada grew slightly but did not offset the decline in conventional production.

2 In macroeconomics, a recession is commonly defined as a decline in a country's gross domestic product (GDP), or negative real economic growth, for two or more consecutive quarters.

Natural gas liquids (NGLs) production declined as natural gas production declined. In addition, economic conditions in the first half of 2009 depressed demand for petrochemical feed stocks, so many producers decided to leave the liquids in the natural gas streams.

Canadian electricity industry activity during 2009 focused on increasing renewable generation and improving the reliability of the grid, as well as encouraging conservation and improving efficiency. The economic downturn changed the economics of many planned projects and as a result, power projects in some provinces were deferred, downsized or cancelled. In 2009, electricity consumption continued its decline due to a mix of economic downturn, cooler summer weather, increased efficiency and conservation efforts. Of significance is the decrease in demand for industrial use in Ontario. Electricity prices remained relatively stable during the year with lower prices for natural gas lowering electricity costs in the provinces that rely on natural gas for power generation. Net exports decreased by eight per cent with export revenue falling considerably as a result. It is expected that an economic recovery in North America could lead to higher electricity prices and increased export revenues.

2009 was a difficult year for many global economies. Demand for energy was down and prices were down, which benefited energy consumers and challenged energy producers. In 2010, there is increased optimism that global economies are in the midst of a recovery. While increased energy prices generally have a negative impact on energy consumers, increased demand and prices for energy commodities tend to have a positive impact on the Canadian economy.

Energy and the Canadian Economy

> *Key Findings:*
>
> - Energy and economy are highly integrated – overall energy production and consumption in Canada declined while the economy declined by 2.5 per cent
> - On average, energy prices were lower in 2009, resulting in declines of energy export revenues from $133 billion to $81 billion, about 40 per cent
> - Oil prices averaged about US$62/bbl in 2009, compared to about US$100/bbl in 2008
> - There has been an eight per cent decline in per capita end-use energy demand over the last five years
> - 2009 marks the first time Canada experienced negative year-to-year economic growth since 1991
> - Canadians remained interested in environmental issues during the economic downturn

The Canadian economy in 2009 saw a continuation of the downturn that began in mid-2008. The financial crisis and the worsening economic conditions that characterized the latter half of 2008 led to concern from Canadians in 2009 that the recession could be deep and long-lasting. As the year progressed, the Canadian economy showed signs of a recovery and by year-end, Canadians were cautiously optimistic that a recovery was beginning.

Energy and the Canadian economy are highly integrated, and the energy industry was affected by the economic downturn. Table 2.1 features several key statistics highlighting the relationship between energy and the economy in Canada. It shows that the energy industry's direct contribution to GDP, export revenues, and labour force all fell in 2009 relative to 2008 levels. An important factor in this change was a decline in energy prices. As shown in Table 2.1, the average price of oil fell 38 per cent in 2009 relative to 2008 levels.

In 2009 net energy export revenue (the value of energy exports minus the value of energy imports) also fell compared with 2008 levels, from $73 billion to $42 billion, a 43 per cent decline (Figure 2.1).

TABLE 2.1

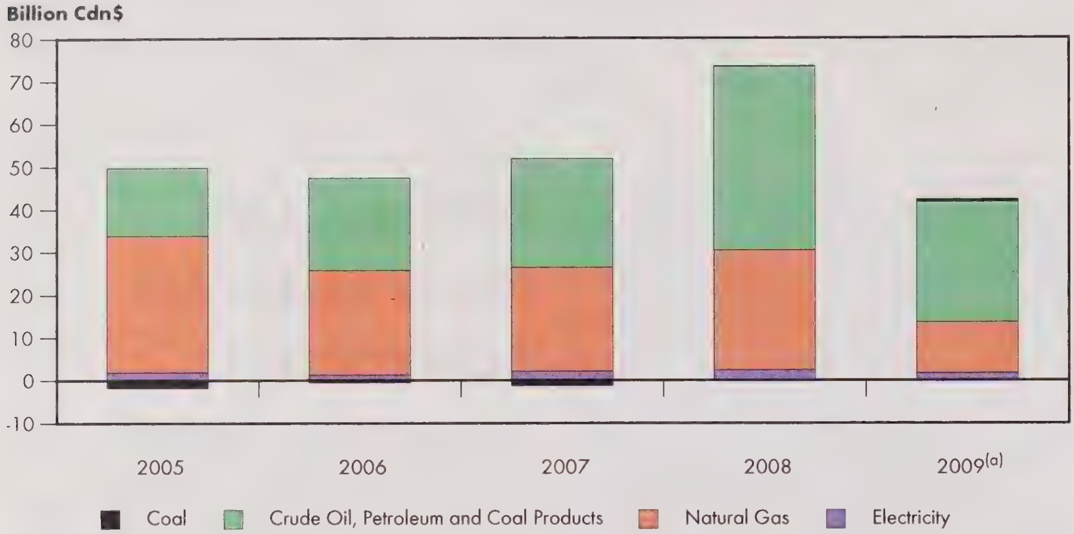
Key Statistics on Energy and the Economy

	2008	2009	Difference, 2008-2009
The energy industry's direct contribution to GDP (per cent)	6.9	6.7	-0.2
Annual energy export revenues (Billion $)	133	81	-52
The energy industry's direct contribution to export revenues (per cent)	27	23	-4
Per cent of labour force directly employed by the energy industry	2	1.8	-0.2
Monthly Average Oil Price ($US/bbl)	99.57	61.65	-37.92

Sources: Statistics Canada, Energy Information Agency

FIGURE 2.1

Net Energy Export Revenues, 2005-2009



(a) Estimate

Sources: Statistics Canada, NEB

Net export revenue of natural gas fell nearly 60 per cent, marking the third year in a row that the net export revenue from crude oil exceeded that of natural gas.

Declining economic conditions contributed to a 3.2 per cent decrease in overall Canadian energy production in 2009 (Table 2.2). While petroleum and wind production did gain compared with 2008 levels, it was not enough to offset the declines in the other commodities.

TABLE 2.2

Domestic Energy Production by Energy Source (petajoules)

	2005	2006	2007	2008	2009[a]	% Change, 2008-2009
Petroleum[b]	6 612	6 908	7 126	6 821	6 836	0.2%
Natural gas[c]	6 559	6 589	6 481	6 395	6 029	-5.7%
Hydroelectricity	1 290	1 258	1 317	1 329	1 308	-1.6%
Nuclear	1 103	1 184	1 098	1 131	1 089	-3.7%
Coal	1 401	1 419	1 506	1 478	1 366	-7.6%
Wind	6	9	10	13	22	69.4%
Other[d]	612	527	581	591	543	-8.1%
Total	**17 583**	**17 895**	**18 120**	**17 758**	**17 193**	**-3.2%**
Annual % Change	**-0.3%**	**1.8%**	**1.3%**	**-2.0%**	**-3.2%**	

(a) Estimates

(b) Petroleum includes crude oil and gas plant natural gas liquids (NGLs), upgraded and non-upgraded bitumen and condensate

(c) Marketable natural gas

(d) Includes solid wood waste, spent pulping liquor, wood and other fuels for electricity generation

Sources: NEB, Statistics Canada, Natural Resources Canada

TABLE 2.3

Domestic Secondary Energy Consumption (petajoules)

	2005	2006	2007	2008	2009[a]	% Change, 2008-2009
Residential[b]	1 396	1 335	1 439	1 463	1 467	0.3%
Commercial	1 493	1 420	1 471	1 498	1 433	-4.4%
Industrial[b][c]	5 246	5 280	5 509	5 207	4 787	-8.1%
Transportation	2 479	2 479	2 590	2 587	2 515	-2.8%
Total	**10 614**	**10 514**	**11 009**	**10 756**	**10 203**	**-5.1%**
Annual % Change	**-0.7%**	**-0.9%**	**4.7%**	**-2.3%**	**-5.1%**	

(a) Estimates

(b) Includes biomass (wood and pulping liquor)

(c) Includes producer consumption energy use and non-energy use

Sources: NEB, Statistics Canada

Domestic energy consumption also declined in 2009. Changes in population, economic conditions, energy prices, weather, conservation, technology, and consumer preferences all combine to shape Canadian energy use. Overall, there has been an eight per cent decline in per capita energy consumption over the last five years.

Secondary energy demand (also known as end-use demand) is the energy used by the final consumer in Canada (i.e., residential, commercial, industrial and transportation sectors). Initial estimates suggest a 5.1 per cent decline in total secondary energy use in 2009 (Table 2.3). Although the residential sector is expected to achieve some modest growth, consumption in the other three sectors decreased. For the industrial and transportation sectors, 2009 marks the second year in a row that declines were observed.

Economic conditions are perhaps the most important driver of energy demand. As noted previously, the 2.5 per cent decline in Canada's real GDP, an indicator of economic activity, marks the first time Canada experienced negative year-to-year economic growth since 1991.

Canadians closely watch fuel prices in the transportation sector. The Canadian yearly averages for regular gasoline and diesel retail pump prices in 2009 were 17 and 28 per cent lower, respectively, than average 2008 levels. These prices were also considerably less volatile in 2009. Despite lower and less volatile prices in 2009, energy use in the sector is estimated to have declined. This highlights the relative importance of the negative income effect associated with the economic downturn, again illustrating the significant interrelationship between energy and the economy.

2.1 Environmental Initiatives

The Copenhagen Conference was notable for several reasons, including its high public profile, which reflected the growing importance of climate issues across the globe, and the increased role of major developing countries in the negotiation process.

There were several domestic environmental initiatives of note in 2009, suggesting that during the economic downturn Canadians remained interested in environmental issues. Environment Canada released draft legislation for a federal light duty fuel economy standard in December, while Quebec

The Copenhagen Accord

The main result of the UN Climate Change Conference in Copenhagen, Denmark which occurred in December was *The Copenhagen Accord*. While the accord is not yet binding, many countries including Canada have agreed to its principles and will work toward starting its implementation in 2010.

The main terms of the accord are:

- **Temperature Goal:** limit the global temperature increase to two degrees Celsius. This goal is subject to review before 2015, perhaps to strengthen it.
- **Documentation of Emission Reduction Targets and Strategies:** Developed countries are to record their economy-wide emission targets for 2020. (Canada has done this, announcing its new target of 17 per cent below 2005 levels in 2020. This target matches the proposed target of the U.S.) Developing countries are to record their mitigation actions and strategies.
- **Measurement, Reporting, and Verification:** Developed countries are subject to international standards. Developing countries are to follow national standards which will be subject to international review and consultation, with the provision that national sovereignty will be respected. However, developing country actions which receive international support will be subject to the international guidelines.
- **Financing Developing Country Actions:** Developed countries collectively commit to supplying initial funds, and to mobilize funds for the future, for developing country mitigation and adaptation activities.
- **Establishment of Additional Tools:** The accord calls for the establishment of a variety of tools to facilitate the aforementioned initiatives.

also announced a fuel economy standard. In April 2010, the federal government announced a joint Canada-U.S. fuel efficiency standard, expected to improve the greenhouse gas performance of new light duty vehicles sold in Canada by 25 per cent in 2016, as compared to the 2008 average. On the renewable energy front, Ontario passed its *Green Energy Act*, designed to enable renewable energy projects and help Ontarians use energy more efficiently.

2.2 Looking Ahead

In 2009, Canadians were concerned about how deep and long-lasting the recession would be. In 2010, the big question is the strength of the recovery. Although risks remain, growth in the third and fourth quarters of 2009 suggests that economic growth will continue in 2010. An economic recovery will have a wide range of implications for the energy sector.

Another factor in looking ahead is the effect of the further development of environmental initiatives relating to climate change and the energy sector. Of key interest is the progress of such initiatives in the United States. Canada has indicated an intention to harmonize its legislation and policies with those of the U.S. in this area. Therefore, further developments in the U.S. are likely to have implications for the Canadian energy industry.

Potential for Economic Recovery in 2010

One of the biggest issues in the near future for Canadian energy is whether or not the initial evidence of an economic recovery witnessed in 2009 turns into a robust upturn in economic activity in 2010. While there are considerable risks, all of the major banks are forecasting a strong economic outlook for Canada in 2010.

Main forces driving the recovery:

- Strong global economic growth, led by major emerging markets such as China, India, and Brazil which is increasing the demand for many commodities and putting upward pressure on their price.
- Economic stimulus activities, including fiscal and monetary measures.

Main risks to the recovery:

- High Canadian dollar putting downward pressure on the demand for Canadian exports.
- Faltering recoveries in Canada's major trading partners.

Upstream Oil and Gas Activity

> ***Key Findings:***
>
> - Lower demand for oil and natural gas led to lower prices and reduced upstream activity
> - The total number of wells drilled in Canada was down about 50 per cent from 2008.

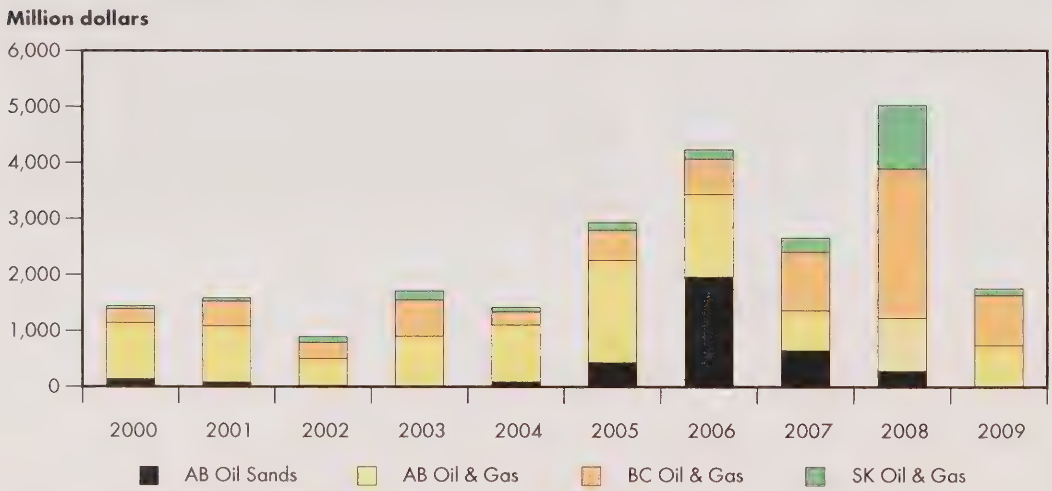
Upstream oil and gas activity can be measured in terms of dollars spent to acquire land rights, the number of active seismic crews, the number of active drilling rigs, the number of wells drilled and the capital expenditures involved.

The economic slowdown lowered the demand for crude oil and natural gas, which, in turn, lowered prices for these commodities. While crude oil prices stabilized in the first quarter of 2009 at around $US 40/bbl, natural gas prices continued to decline through most of the year, reaching lows not seen since 2002. The drop in oil and natural gas prices, compared to year-earlier levels, resulted in reduced drilling and the delay or cancellation of some energy projects, especially in Canada's oil sands. Lower drilling activity also led to a tempering of service industry costs.

Expenditures on petroleum and oil sands rights (Figure 3.1) were lower in 2009 than a year ago for Alberta, Saskatchewan, and British Columbia. The acreage of land rights sold (Figure 3.2), fell to the lowest levels since 1992. This was partially due to lower oil and natural gas prices, but also due to the large purchases of rights in recent years in Saskatchewan's Bakken and Shaunavon formations, Alberta's oil sands and British Columbia's Montney and Horn River Basin formations[3], making

FIGURE 3.1

WCSB Oil, Gas, and Oil Sands Rights Expenditures, 2000-2009



Source: Provincial regulatory agencies

3 See also *A Primer for Understanding Shale Gas*, available at http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/prmrndrstndngshlgs2009/prmrndrstndngshlgs2009-eng.html

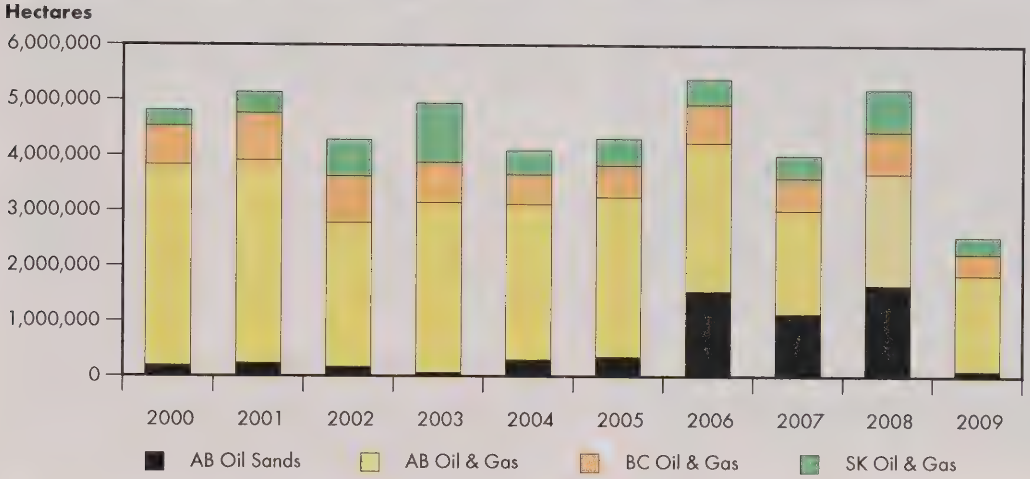
significantly less land available for auction in 2009. In particular, land activity in the oil sands virtually disappeared from 2008 to 2009.

Eastern Canada had $59.7 million under work bid commitments for 2009 on 1.06 million hectares of land. This marks a drop of nearly 90 per cent from last year when Nova Scotia alone received $353 million in work commitments and Newfoundland and Labrador received $319 million. The majority of 2009 work commitments came in a fourth quarter sale for rights in offshore Newfoundland and Labrador.

The number of active rigs in western Canada fell in 2009 (Figure 3.3) because of low oil and gas prices. Weekly rig activity fell by 41 per cent in 2009 to the lowest level since 1992. The three westernmost provinces all saw decreased rig activity, with Alberta having the highest decline at nearly 50 per cent and British Columbia with the lowest at approximately 25 per cent. Further, the total

FIGURE 3.2

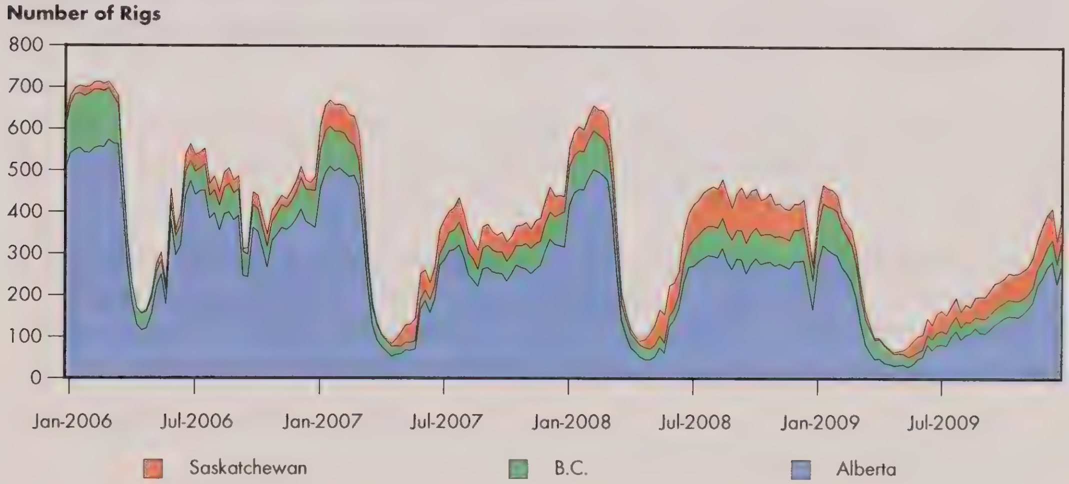
WCSB Oil, Gas, and Oil Sands Rights Activity, 2000-2009



Source: Provincial regulatory agencies

FIGURE 3.3

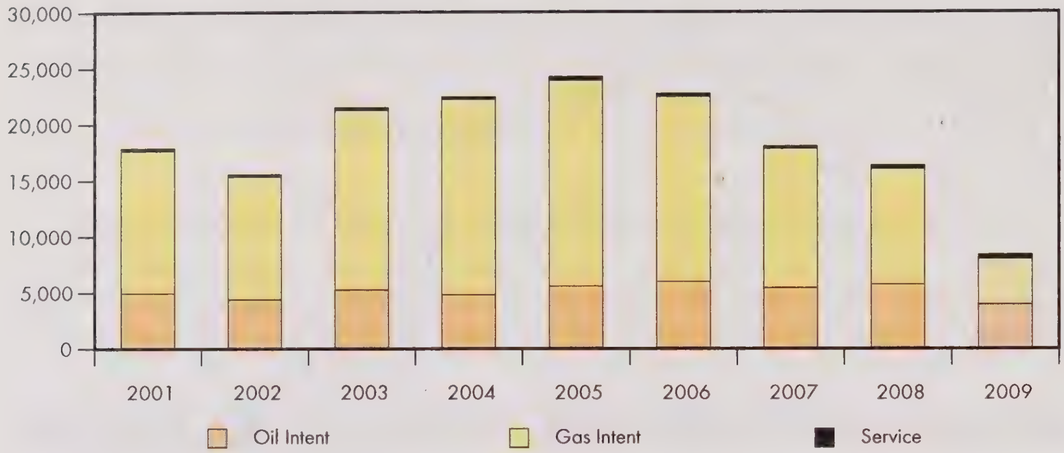
Western Canada Rig Activity



Source: Nickle's rig data

FIGURE 3.4

Number of Wells Drilled – Western Canada, 2001-2009



Source: NEB

metres drilled fell by 43 per cent as compared to 2008 levels to 12.5 million metres.[4] Despite this, the average length of wells drilled rose 15 per cent to 1 517 m as exploration companies increasingly relied on horizontal drilling.

The total number of wells drilled in Canada decreased about 50 per cent from 2008 levels, although the decrease was not evenly split between oil and gas (Figure 3.4). The number of wells targeting oil dropped by about one-third, while the number of wells targeting gas dropped by closer to two-thirds. Between 2003 and 2005, over 80 per cent of Canadian wells targeted natural gas. In 2009, natural gas drilling accounted for roughly 50 per cent of wells drilled.

Total oil and gas capital expenditures in Canada fell by one-third from 2008 levels to an estimated $33.3 billion. Capital spending associated with oil sands projects also fell by one-third to an estimated $13.5 billion.

3.1 Looking Ahead

A number of project postponements and cancellations marked a slow year for oil sands operators in 2009. During the fourth quarter, however, increased oil prices and improved forecasts led to producers reinstating certain deferred projects. Oil sands' spending is expected to rise by just over ten per cent in 2010 to $15.0 billion.

Industry has been forecasted to increase its total spending by almost ten per cent in 2010, to $36.4 billion.[5] The Petroleum Services Association of Canada has projected that 9 000 wells will be drilled in the Western Canada Sedimentary Basin (WCSB) in 2010, compared to 16 895 in 2008.

With oil prices rising above 2009 levels and the potential for gas prices to do the same, companies could begin acquiring drilling rights to additional prospective land surrounding the core areas of gas shales in British Columbia, the oil sands of Alberta, and the Bakken oil play in Saskatchewan. However, it is not likely to cause land sale proceeds to reach the highs seen in recent years.

4 Nickle's Daily Oil Bulletin.

5 Statistics Canada. *Private and Public Investment in Canada, Intentions.* 2010.

Crude Oil and Petroleum Products

4.1 International Markets

For much of the first quarter of 2009, the near-month contract for West Texas Intermediate (WTI) traded below US$40/bbl. A recovery in global equity markets beginning in March led to gradually rising oil prices, although demand remained weak and global inventories remained high. Oil prices averaged about US$62/bbl in 2009, compared to about US$100/bbl in 2008 (Figure 4.1).

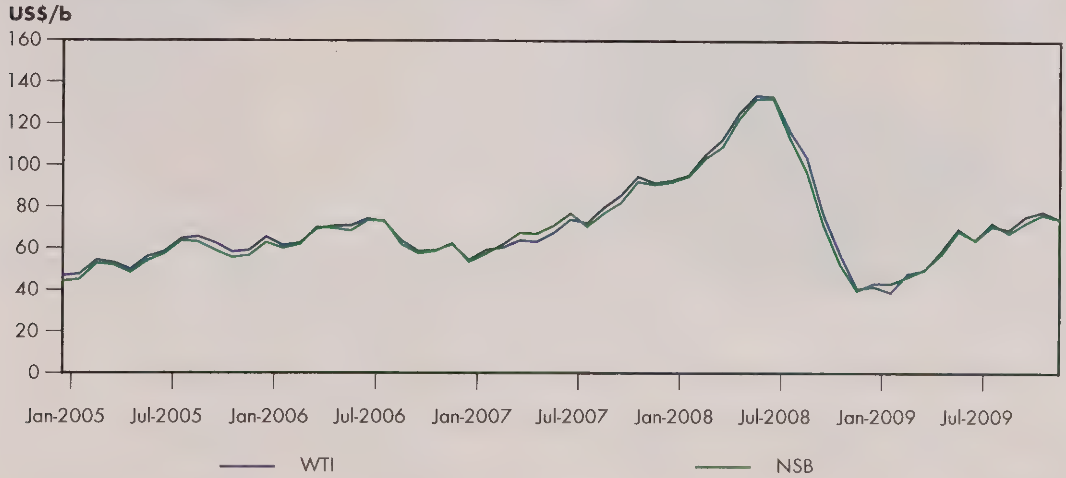
The drivers that led to record prices in the summer of 2008, including tight supply and demand conditions, substantial financial investment in commodities, and ongoing geopolitical risks were replaced by the reality that global oil demand had declined and inventories were rising to high levels. Against this backdrop, OPEC maintained the substantial production cuts it announced in late 2008. By June, WTI was trading at about US$70/bbl, nearly double the lows seen in January.

Key Findings:

- Oil sands production grew to 49 per cent of total crude oil production
- Weak demand and high global inventory levels in first half of 2009 led to lower oil prices
- Despite a slight increase in the volume of crude oil exports, lower oil prices in the first half of the year resulted in lower export revenue for crude oil and petroleum products
- In the second half of the year, oil prices and activity levels increased
- Domestic prices for crude oil, gasoline and diesel were much lower compared with 2008

FIGURE 4.1

WTI and North Sea Brent Oil Prices, 2005-2009



Source: U.S. Energy Information Administration (EIA)

Over the second half of 2009, oil prices averaged about US$70/bbl. While the OECD economies experienced modest economic recovery, the oil market was supported by emerging economies including China which experienced stronger growth. The WTI near-month contract ended the year at about US$79/bbl.

4.2 Canadian Oil Production and Reserves Replacement

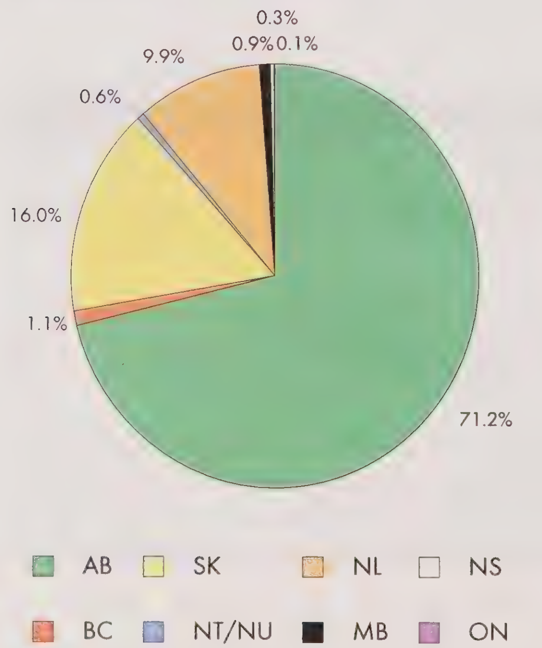
In 2009, Canadian production of crude oil and equivalent averaged 433 300 m^3/d (2.73 MMb/d), an increase of less than one per cent from 2008 levels. Figure 4.2 illustrates crude oil production by province and shows that Alberta is the largest producer by a considerable margin, largely due to oil sands production. Oil sands production grew in 2009, but this gain was almost entirely offset by falling conventional crude oil production in the WCSB. On the east coast offshore production decreased, reflecting natural pool decline as well as some maintenance down time at the White Rose and Hibernia fields.

Figure 4.3 illustrates crude oil and equivalent production by type and shows that non-upgraded bitumen and synthetic crude oil, from the oil sands, now constitute about one-half of Canadian production.

While remaining conventional established reserves are reduced by production each year, these reductions are offset to some degree by new discoveries, extensions to existing pools and revisions to reserve estimates in existing pools. From 2004 to 2007, cumulative additions to established reserves of conventional light and heavy crude oil replaced 87 per cent of production (Table 4.1). In 2008 (the last year for which nearly-complete data is available), 80 per cent of production of conventional crude oil was replaced.

FIGURE 4.2

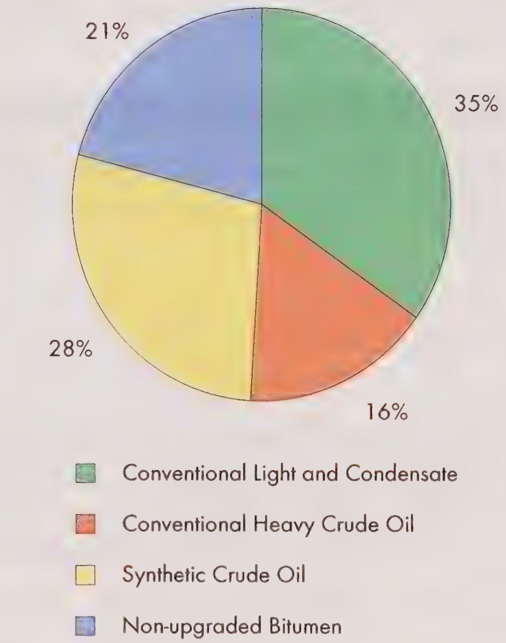
Crude Oil and Equivalent Production by Province



Source: NEB

FIGURE 4.3

Crude Oil and Equivalent Production by Type



Source: NEB

Estimates of remaining established conventional crude oil reserves in Canada decreased (Table 4.2). Most of this decrease can be attributed to production significantly outpacing reserves additions. The remaining established crude bitumen reserves decreased slightly, reflecting 2008 bitumen production.

TABLE 4.1

Conventional Crude Oil Reserves, Additions and Production, 2004-2008 (million cubic metres)

	2004	**2005**	**2006**	**2007**	**2008**	**Total**
Additions	66.9	134.7	27	50	62.5	341.1
Production	82.7	78.8	82.1	76	77.9	397.5
Total Remaining Reserves	**640**	**696**	**640**	**614**	**599**	
Total Remaining Reserves (millions of barrels)	**4 027**	**4 382**	**4 033**	**3 871**	**3 774**	

Source: Provincial Energy Agencies, Offshore Petroleum Boards, NEB

TABLE 4.2

Estimates of Established Reserves of Crude Oil and Bitumen at 31 December 2008 (million cubic metres)

Conventional Crude Oil	**Initial**	**Remaining**
British Columbia[a]	129.1	18.5
Alberta[b]	2 773.1	233
Saskatchewan[c]	926.1	180.7
Manitoba[d]	47.1	7.7
Ontario[e]	14.9	1.6
Northwest Territories, Nunavut and Yukon		
Arctic Islands and Eastern Arctic	0.5	0
Mainland Territories - Norman Wells and Cameron Hills	52.8	12.7
Nova Scotia - Cohasset and Panuke[d]	7	0
Newfoundland - Hibernia, Terra Nova and White Rose[d]	302.5	144.8
Total	**4 253.1**	**599**
Total (millions of barrels)	**26 794.5**	**3 773.7**
Crude Bitumen		
Oil Sands - Mineable[f]	6 157	5 487
Oil Sands - Bitumen[f]	21 935	21 585
Total	**28 092.0**	**27 072.0**
Total (millions of barrels)	**176 980**	**170 554.0**
Total Conventional and Bitumen	**32 345.1**	**27 671.0**
Total Conventional and Bitumen (millions of barrels)	**203 774.1**	**174 327.3**

(a) British Columbia Ministry of Energy & Mines and NEB common database.

(b) Alberta Energy Resources Conservation (ERCB) Board and NEB common database.

(c) Canadian Association of Petroleum Producers/NEB estimates 2007.

(d) Provincial Agencies or Offshore Boards, NEB estimates for Manitoba 2007, Newfoundland 2008.

(e) Canadian Association of Petroleum Producers.

(f) ERCB Report - ST 98 2009.

Note: totals may not add due to rounding.

4.3 Oil Sands

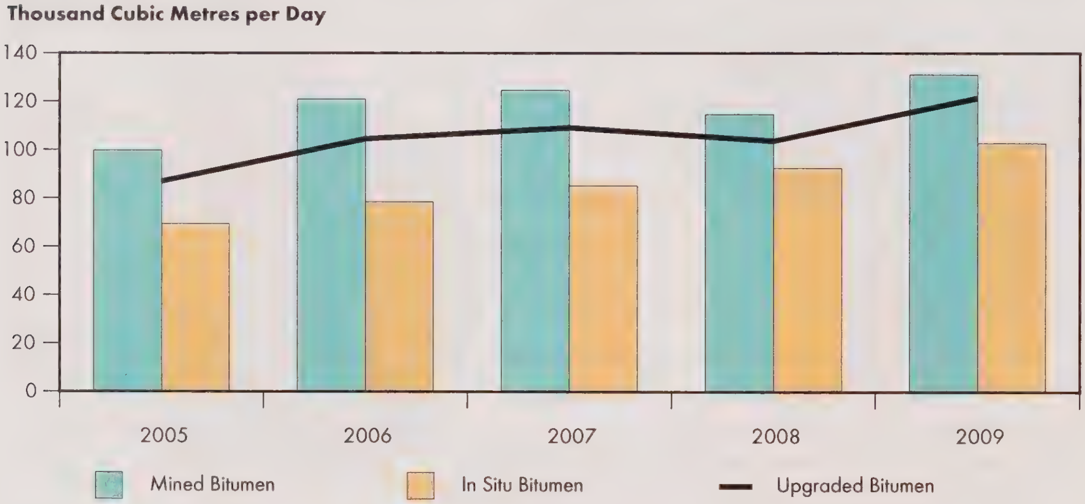
The global economic downturn and corresponding lower oil prices continued into the first quarter of 2009, and resulted in the deferral or cancellation of several new oil sands projects, as well as the shut-in of some production. By the fourth quarter, however, and with indications that the slow-down in development activity lowered construction costs of new projects by 20 per cent, there was renewed investment interest in Canada's oil sands. Oil sands capital expenditures, not including mergers and acquisitions, were estimated to be about $12 billion in 2009 compared with $16 billion in 2008.

In 2009, crude bitumen production (before processing) from mining and in situ operations totalled 234 000 m^3/d (1.47 MMb/d), an increase of 13 per cent compared with 2008. In situ bitumen production increased by 11 per cent to 102 800 m^3/d (648 Mb/d) while bitumen from mining operations increased by 14 per cent to 131 200 m^3/d (827 Mb/d) (Figure 4.4). All of the mined bitumen, and about nine per cent of the in situ bitumen was upgraded, yielding 121 500 m^3/d (765 Mb/d) of synthetic crude oil, an 11 per cent increase over 2008. Opti/Nexen's Long Lake project, which couples a surface upgrader with an in situ steam-assisted-gravity-drainage (SAGD) operation, is the first oil sands project to utilize gasification of bitumen residue, or asphaltenes, to produce syngas (synthetic gas) within the upgrader, hence minimizing the need to purchase and use natural gas for steam generation.

Oil sands producers are faced with a number of environmental challenges, including those associated with air emissions/quality, land disturbance/reclamation, and water use/quality. In the area of greenhouse gas (GHG) emissions, companies have made 2.6 million tonnes of reductions – the equivalent of taking 550,000 cars off the road.[6] In addition, more than 80 per cent of water drawn by industry from the Athabasca River is recycled.[7]

FIGURE 4.4

Crude Bitumen Production, 2005-2009



Source: NEB

6 Oil Sands Developers Group, Oil Sands Facts, September 2009. http://www.oilsandsdevelopers.ca/wp-content/uploads/2009/10/OSDG-Fact-Booklet-2009.pdf

7 Ibid.

Oil Sands Tailing Ponds

Oil sands tailings are a mixture of water, clay, sand and residual bitumen that result from oil sands mining operations. They are stored in large ponds where the clay/water mixture is left to settle. In 2009, tailings ponds covered an area of 130 square kilometres (an area the size of the city of Vancouver).[1]

In February 2009, the ERCB issued Directive 74, *Tailings Performance Criteria and Requirements for Oil Sands Mining Schemes*, which applies to all mineable oil sands operations. It requires the reduction of fluid tailings, their capture in ERCB-approved dedicated disposal areas and their conversion to trafficable deposits, which mean they can be walked upon and bear the weight of heavy equipment within a given time frame. There are many different technologies being researched and tested.

1 Terra Simieritsch, Pembina Institute, Backgrounder: Oil Sands Tailings and Directive 074, December 2009. http://pubs.pembina.org/reports/tailings-directive-074-backgrounder.pdf

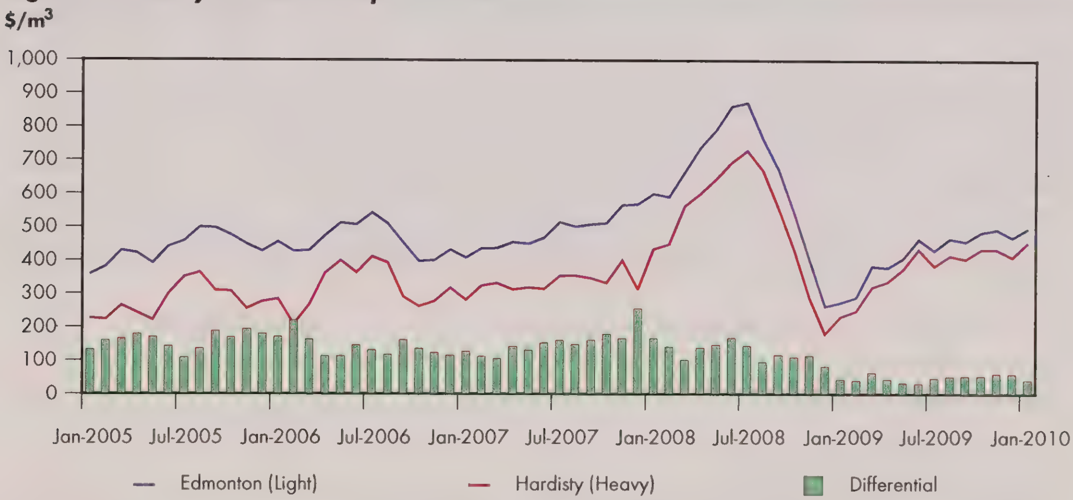
4.4 Crude Oil Exports and Imports

In 2009, crude oil exports averaged approximately 291 900 m^3/d (1.84 MMb/d), an increase of two per cent compared with 2008. The average light and heavy crude oil export prices were $417 per cubic metre and $369 per cubic metre ($66 and $58 per barrel), respectively, compared with $647 and $520 per cubic metre ($103 and $83 per barrel) in 2008 (Figure 4.5). The estimated value of crude oil exports for 2009 is $38.9 billion compared with $60 billion in 2008. The drop is attributable to lower crude oil prices.

Heavy and light crude oils are traded in separate markets and, accordingly, the prices for each vary as a result of the supply and demand for each crude type. Heavy crude oil has a smaller market, higher refining costs and generally yields lower volumes of high value products such as gasoline and, as a

FIGURE 4.5

Light and Heavy Crude Oil Export Prices



Source: NEB

result, is usually discounted. The differential typically narrows in the summer months because of increased use of heavy crude oil used in the production of asphalt and widens again in September.

The light-heavy differential averaged $47.87/m³ ($7.60/bbl) during 2009, much narrower than 2008. Although pipeline capacity can impact the light-heavy differential, other factors played a larger role in setting the differential in 2009. These factors included: reduced global consumption causing a drop in overall prices which impacted light crudes more than heavy crudes; increased demand for heavy crude oil with the addition of new heavy conversion capacity; and reduced supply of medium to heavy sour crude stemming from OPEC production cuts. The differential is expected to remain narrow in the medium term.

Canada remained the number one supplier of crude oil to the U.S. followed by Mexico and Saudi Arabia.[8] According to the EIA, the U.S. imported approximately 307 000 m^3/d (1.9 million b/d) of crude oil from Canada, which equates to roughly 21 per cent of their total imports of 1.4 million m^3/d (9.1 million b/d).

The U.S. market is divided into regions called Petroleum Administration for Defense Districts or PADDs (Figure 4.6). In aggregate, Canada exported more oil to PADD II than any other region. Almost all Canadian exports were delivered to U.S. destinations in 2009, with small volumes sent to other regions of the world.

In 2009, crude oil imports were estimated to be 128 400 m^3/d (809 Mb/d). This is a decrease of five per cent compared with 2008 and represented approximately 50 per cent of total Canadian refinery supply. Canada imports crude oil from a number of sources, including: OPEC, the North Sea and

TABLE 4.3

Crude Oil Exports by Type and Destinations – 2009 (volume – m^3/d)

Market	Light	Medium	Heavy	Synthetic	Blended Bitumen	Total
PADD I	21 289.80	102.30	5 829.70	1 063.80	48.00	28 333.60
PADD II	26 111.50	8 165.00	50 681.30	43 905.60	56 610.40	185 473.80
PADD III	3 155.10	69.40	3 586.00	2.20	10 866.10	17 678.80
PADD IV	3 892.70	760.50	21 875.40	6 220.50	2 025.20	34 774.30
PADD V	12 845.90	0.00	0.00	7 500.20	2 924.90	23 271.00
Total U.S.	**67 295.00**	**9 097.20**	**81 972.40**	**58 692.30**	**72 474.60**	**289 531.50**
Other	52.10	27.40	157.20	247.40	1 902.30	2 386.40
Total	**67 347.10**	**9 124.60**	**82 129.60**	**58 939.70**	**74 376.90**	**291 917.90**

Notes:

PADD - Petroleum Administration for Defense District (see Figure 4.7)

Light – greater than 30 API

Medium – between 25 and 30 API

Heavy – less than 25 API

Synthetic – upgraded bitumen of any API

Blended Bitumen – Bitumen blended with light hydrocarbons and/or synthetic crude oil

Source: NEB Estimates

8 U.S. Energy Information Administration (EIA).

FIGURE 4.6

Crude Oil Supply and Disposition, 2009
(thousand cubic metres per day)

Source: NEB

North America. An estimated 86 per cent of the Atlantic refining requirements were met by imports and the remaining 14 per cent came from offshore eastern Canada production. Quebec is the most reliant on imported crude oil with 89 per cent of its refining needs supplied from international sources. Ontario accounted for the remainder of imported crude volumes. Ontario refineries are increasingly sourcing crude oil supplies from western Canada.

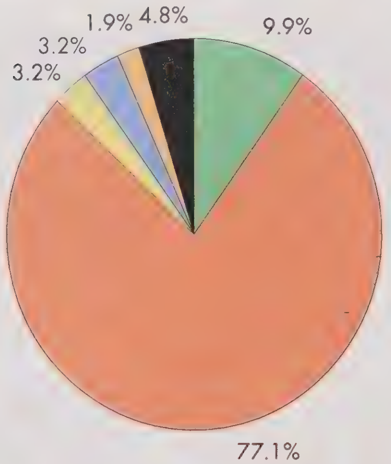
4.5 Oil Refining

There were 19 Canadian refineries operating at the end of 2009 with a total refinery capacity of 334 700 m^3/d (2.1 MMb/d).

Canadian consumption of petroleum products in 2009 is estimated at 238 600 m^3/d (1.5 MMb/d), a four per cent decline from 2008. Refinery runs, refinery capacity utilization and refinery receipts of domestic crude oil all decreased in 2009 compared with 2008. The decrease in refinery receipts of domestic crude oil was due in part to the reduction in refinery runs because of planned and unplanned

FIGURE 4.7

Product Exports by Destination, 2009



Source: NEB

refinery maintenance. Extended refinery outages in western Canada in the fall resulted in a shortage of gasoline and diesel.

4.6 Main Petroleum Product Exports and Imports

Canada is a net exporter of petroleum products. Exports of main petroleum products in 2009 are estimated to be 54 024 m^3/d (339 Mb/d), a marginal decrease from 2008. The primary destination was the U.S. east coast market (PADD I) with overseas exports being the second largest market (Figure 4.7).

The estimated revenue in 2009 from exports of main petroleum products, including partially processed oil, was $8.2 billion, down from about $10.5 billion in 2008.

4.7 Product Prices

According to Natural Resources Canada (NRCan)[9], average Canadian retail product prices were approximately 26 per cent lower in 2009 compared with 2008. Retail gasoline prices in Canada decreased in 2009 compared with 2008 (Table 4.4). The price of diesel fuel, which is closely linked with economic activity, dropped more than gasoline.

TABLE 4.4

World Oil and Canadian Products Prices

Product	2008 (cents/litre)	2009 (cents/litre)	Change	Change (%)
Gasoline	114	94.6	-19.4	-17%
Diesel	124.9	89.6	-35.3	-28%
Furnace oil	113.2	76.2	-37	-33%
WTI (US$/bbl, Cushing, OK)	99.67	61.95	-37.8	-37.80%
Edmonton Par (Cdn$/bbl)	102.73	65.36	-37.4	-36.40%

Source: NRCan, EIA, NEB

4.8 Looking Ahead

For 2010, the emerging economies led by China and India, are expected to continue to perform well, and moderate growth is likely in the U.S., Europe and Japan. Oil demand growth in Asia is expected to lead to rising prices for both crude oil and gasoline this summer. In this regard, OPEC may decide to increase production in the second half of the year, if prices move above $US80/bbl. Oil prices are forecast to be slightly above that level in 2010. In 2010, production from the oil sands will continue to grow because of already established, and expansions to, existing projects.

9 Natural Resources Canada, Fuel Focus, 2009 Annual Review, 15 January 2010.

Natural Gas

5.1 North American Natural Gas Markets

Key Findings:

- The average price of natural gas was half of what it was in 2008
- Natural gas production was eight per cent less than in 2008 and net export revenues declined by 57 per cent
- Evaluation and development of shale gas continued
- In 2009, Canada received its first LNG import at the Canaport facility
- Overall natural gas consumption was stable

Together, the Canadian and U.S. natural gas markets operate as one large integrated market. This market offers the benefit of flexibility with numerous supply and transportation options. Events in any one region will affect the other regions.

In 2009, more than a fifth of North American natural gas was produced in Canada. About 98 per cent of Canadian gas came from the WCSB, with Alberta producing roughly 76 per cent of that. British Columbia and Saskatchewan contributed approximately 18 and four per cent, respectively, of total Canadian production. Production from the WCSB remained steady through the first half of the year at 432 million m^3 per day (15.2 Bcf/d) before declining by nearly ten per cent in the second half of the year to 393 million m^3 per day (13.98 Bcf/d). Production from the east coast also declined in 2009 due to maintenance at the Sable Offshore Energy Project.

Supply in the U.S. was relatively steady over the year largely due to gains in unconventional gas production; however, there was also reduced natural gas consumption in the industrial sector primarily due to the economic downturn. North American natural gas prices, represented by the Henry Hub price[10], declined through the first three quarters of the year (Figure 5.1) and averaged US$3.95/MMBtu. The benchmark for Western Canadian natural gas is the Intra-Alberta/NIT trading price[11], which followed a similar path as the Henry Hub price, and averaged $3.81/GJ, approximately half of that in 2008.

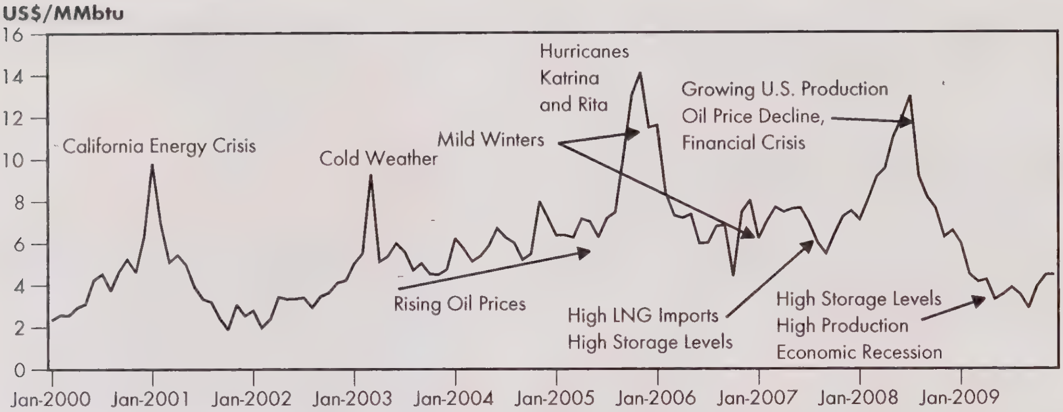
Gas consumption is normally higher in the winter months than in the summer months because there is greater need for space heating in the winter. However, gas production tends to remain relatively constant year round. To balance production with consumption, gas is injected into underground storage in the summer and withdrawn in the winter. April is the beginning of the typical storage injection season (Figure 5.2). Gas storage inventories were at near normal levels at the start of 2009. Spring was characterized by growing storage inventories as the economic downturn began to slow industrial gas consumption. By May, storage inventories began to exceed the five-year range for that time of year. Storage continued to fill at an above-normal pace and by the end of October, the usual

10 The Henry Hub price for natural gas is the benchmark natural gas price for North America.

11 The Intra-Alberta/NIT price is also known as the AECO price. Historically, AECO was the name of a group of storage fields located in southeastern Alberta and operated by the Alberta Energy Company (now EnCana) and the Nova Inventory Transfer (NIT) is a title transfer service operated by TransCanada PipeLines Limited.

FIGURE 5.1

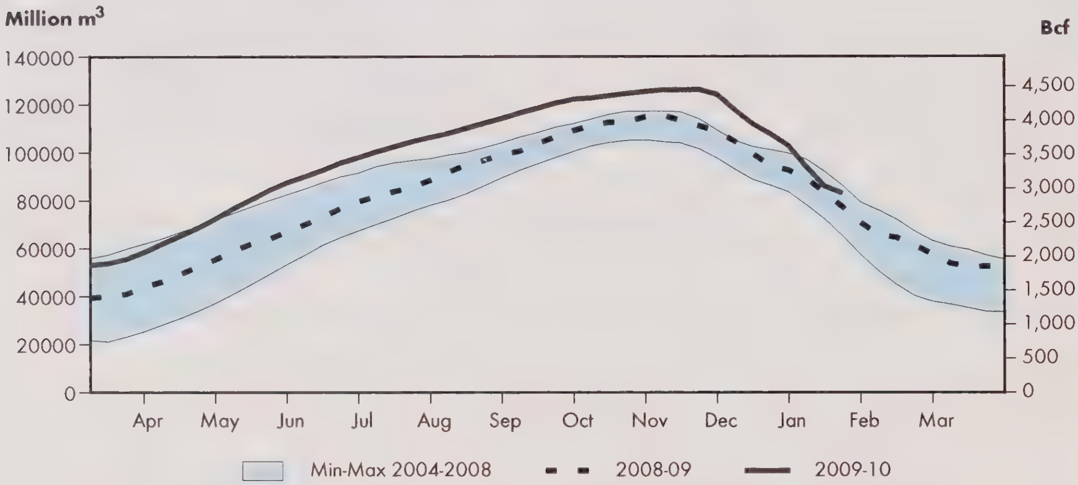
North American Gas Price Trends – Henry Hub (Monthly average)



Source: GLJ Publications Inc.

FIGURE 5.2

North American Gas Storage Levels



Sources: Canadian Enerdata Ltd., NEB estimates, U.S. Energy Information Administration

start to the winter storage withdrawal season, North American natural gas inventories were at their highest level ever: 24.5 billion m^3 (4 394 Bcf). Despite a very cold December in much of Canada and the U.S., storage inventories were still well above the five-year range by the end of 2009.

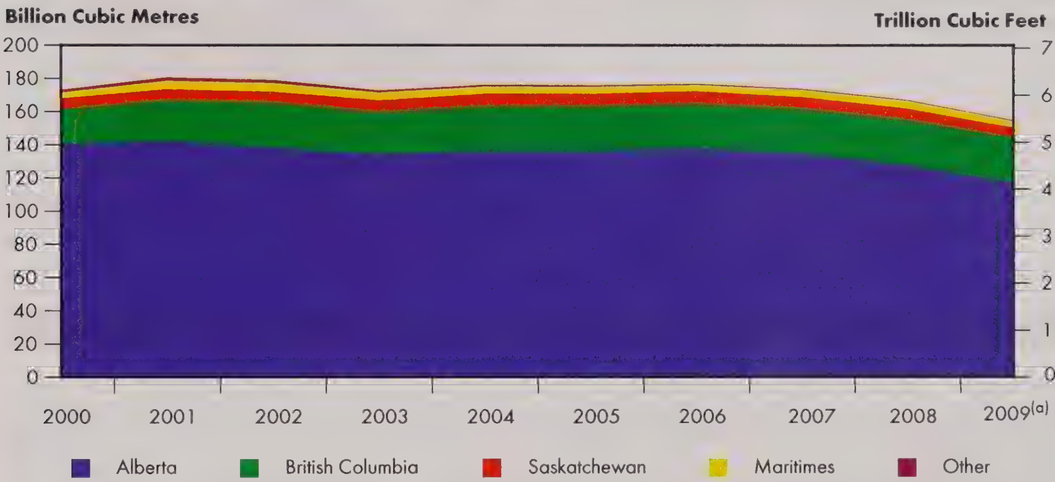
5.2 North American Natural Gas Supply

Canadian natural gas production averaged 423 million m^3/day (14.8 Bcf/d) in 2009. This is 21 per cent of North American production, down from 25 per cent in 2006. Further, Canadian production was eight per cent less than in 2008 (Figure 5.3). The most significant event during the year was the shutting in of many gas wells in September because of very low gas prices, which reduced Canadian production by about 30 million m^3/d (1.1 Bcf/d) over the course of a few weeks.

No region in Canada showed an increase in production in 2009, although British Columbia's production remained essentially flat. In Alberta and Saskatchewan, production declines were due to reduced gas-drilling activity. Production added from new wells no longer offsets or surpasses production declines from older wells. Maritimes production fell 20 per cent, largely due to planned and unplanned maintenance at the Sable Offshore Energy Project, but also as a result of decreases in onshore production.

FIGURE 5.3

Canadian Marketable Gas Production, 2000-2009



(a) Estimates

Sources: Provincial and territorial regulatory agencies

Conservation of natural gas resources

Most provincial regulatory bodies dealing with oil and gas are directed to ensure that the resource is exploited in a way to maximize production and to reduce or even eliminate wasteful practices.

The ERCB of Alberta has been encouraging oil producers to reduce the venting and flaring of solution gas.[1] Solution gas is natural gas that is dissolved in oil at higher pressures underground and, when the oil is exposed to lower pressures at the surface, the gas is expelled. Sometimes this gas is produced at wells in low quantities and therefore may not meet economic thresholds to be shipped via gas pipelines. However, industry cooperation with the ERCB has reduced solution gas venting and flaring by 60 per cent from 1996 to 2008. This has resulted in a reduction in GHG emissions, and has increased the conservation of the solution gas resource from 92 to 95 per cent.

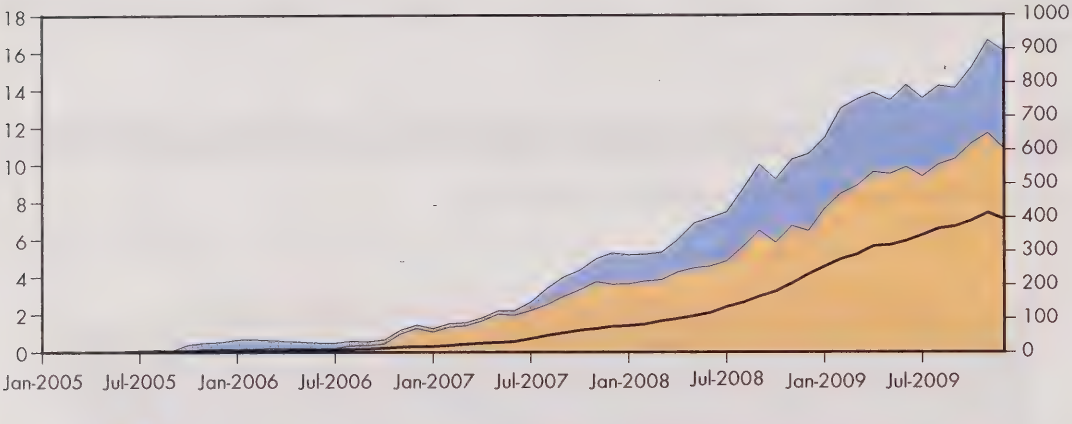
The BC Oil and Gas Commission has also taken steps to reduce venting and flaring of natural gas, with aims of cutting the volume in half by 2011 and eliminating it entirely by 2016[2]. Solution gas flaring and venting in B.C. has been reduced by 86 per cent from 1996 to 2008. Further, flaring and venting from all natural gas production has been reduced by 19 per cent from 1996 to 2008, while British Columbia's raw natural gas production increased by over 42 per cent over the same period. Saskatchewan, which had seen growth in gas flaring over the past several years as oil production rose, is also working towards reducing flaring with a plan similar to Alberta's and is expected to release draft guidelines by June 2010.

1 Energy Resources Conservation Board. ST60B-2009: Upstream Petroleum Industry Flaring and Venting Report, 2008. Released July 2009.

2 BC Oil and Gas Commission. Flaring, Incinerating and Venting Reduction Annual Report. Released September 2009.

FIGURE 5.4

Montney Raw Natural Gas Production



Source: Geovista production data

FIGURE 5.5

Major Shale Gas Prospects in North America

Source: modified from Ziff Energy Group

Note: The triangles attached to the red lines represent mountain fronts, where the triangles point in the direction of landmass that has been overridden by the mountains (i.e. a thrust fault).

Interest in Canadian shale gas (Figure 5.5) continued in 2009. Despite the decline in gas prices, development of the Montney hybrid-shale and tight-gas play continued and its production increased from 2008 levels (Figure 5.4). Horn River Basin shale saw about three dozen wells producing gas by year-end 2009, although specific estimates of total gas production are unavailable at the time of writing. Horn River Basin shale gas production is expected to reach 13 million m^3/d (0.5 Bcf/d) by 2012.[12] Since Horn River shale gas is approximately 12 per cent carbon dioxide (CO_2), there have been a number of proposed projects for carbon capture and sequestration (CCS) facilities associated with its production. However, cost issues have shelved at least one CCS project and it remains to be seen whether other such projects will go ahead as proposed.

In eastern Canada, several wells were drilled in the Utica Shale in Quebec, including a few horizontal wells, with variable but encouraging results. Finally, the Frederick Brook Member of the Horton Bluff Group in New Brunswick had significant gas flow from a vertical well.

There remains significant resource potential in coalbed methane (CBM) even though industry has increasingly focused its efforts on Canadian shale gas. Production of CBM in 2009 averaged approximately 30 million m^3/d (0.85 Bcf/d)[13] of marketable gas, a small increase, yet notable because of the overall reduction in natural gas production across western Canada. In 2009, the first commercial CBM production in British Columbia took place in the Hudson Hope area last year.

Canaport LNG – Canada's first LNG Import Terminal

In 2009, the Canaport LNG terminal received its first cargo of LNG from Trinidad and Tobago and became Canada's first operating LNG import terminal. Co-owned by Repsol and Fort Reliance (Irving Oil Limited), Canaport LNG is a year-round port located in Saint John, New Brunswick.

At the terminal, LNG is received from specially-built ships and stored in large refrigerated tanks. When natural gas is required in the market, the LNG is re-gasified and delivered to market via the 145 kilometre Brunswick Pipeline. At this time, Canaport has an output capacity of about 28.3 m^3/d (1 Bcf/d) and can store 480,000 m^3 of LNG (9.9 Bcf gas equivalent) in three storage tanks.

Since its inaugural cargo, Canaport LNG has received regular LNG shipments and has provided an additional source of gas supply into the regional marketplace. Since making its first delivery in July, gas send-out from the terminal has exceeded 970 million m^3 (35 Bcf), and has averaged over 6 million m^3/d (200 MMcf/d). With the arrival of winter weather, send-outs since December 2009 have been even higher, averaging over 10 million m^3/d (350 MMcf/d).

12 National Energy Board. *Short-term Canadian Natural Gas Deliverability 2010-2012*. March 2010. Available at http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/ntrlgsdlvrblty20102012/ntrlgsdlvrblty20102012-eng.html

13 Includes some commingled production from non-coal strata.

North American LNG[14] imports increased despite lower natural gas consumption and growth in U.S. natural gas production. Growth in world LNG supply, plus reduced natural gas consumption in parts of Asia and Europe due to the global economic recession, led to moderately higher levels of LNG imports coming to North America, which served largely to fill the expanded natural gas storage capacity.

North American LNG imports averaged 43.9 million m³/d (1.55 Bcf/d) up from 37.7 million m³/d (1.33 Bcf/d in 2008). Canaport LNG, Canada's first LNG import terminal (located in Saint John, New Brunswick), became operational in June 2009. This increased the total North American import capacity to over 430 million m³/d (15 Bcf/d) spread at twelve facilities (in addition to Canaport, there are two in Mexico and nine in the U.S.).

5.3 Natural Gas Reserves

The NEB's estimate of remaining marketable gas reserves[15] at the end of 2008 is 1 709 billion m³ (60.3 Tcf) (Table 5.1). This is up 118 billion m³ (4.2 Tcf) from year-end 2007 as reserve additions replaced 170 per cent of annual production in 2008. Major reserves growth came from additions of B.C. Montney shale gas and Alberta tight gas.

TABLE 5.1

Canadian Natural Gas Reserves

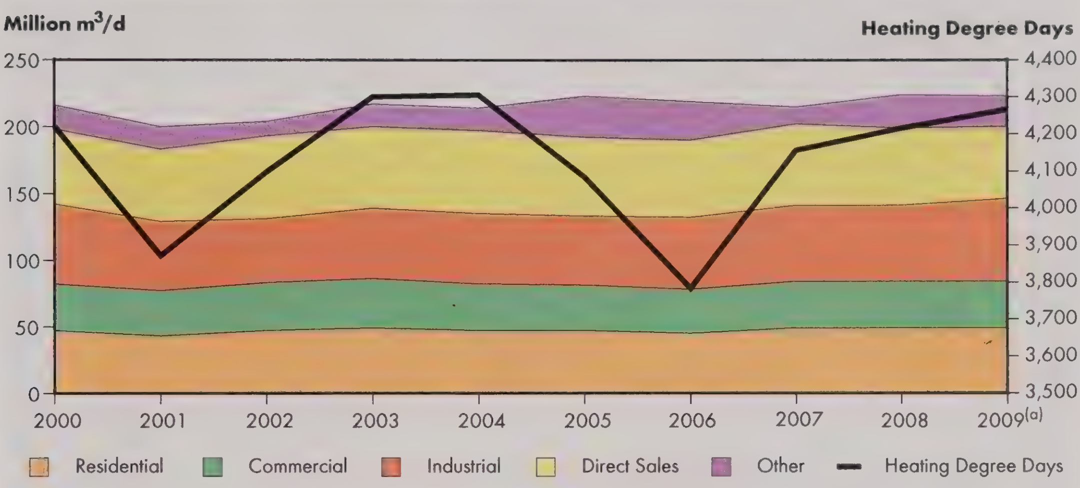
(million m³) At Year-end 2008	Natural Gas Reserves		
	Initial Reserves	**Cumulative Production**	**Remaining Established Reserves**
British Columbia	1 071.1	573.3	496.6
Alberta	5 048.7	3 950.5	1 098.2
Saskatchewan	262.7	191.4	71.3
Subtotal – WCSB	**6 382.5**	**4 715.2**	**1 666.1**
Ontario	54.3	34.6	19.7
New Brunswick	4.1	0.1	4.0
Nova Scotia Offshore	55.0	40.5	14.5
Mainland NWT & Yukon	29.1	16.2	12.8
Mackenzie Delta	0.3	0.1	0.2
Subtotal – Frontier	**88.5**	**56.8**	**27.5**
Total Canada (million m³)	**6 525.3**	**4 806.6**	**1 713.3**
Total Canada (trillion cubic feet)	**230.3**	**169.7**	**60.5**

14 National Energy Board. *Liquefied Natural Gas – "A Canadian Perspective"*. February 2009. Available at http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/lqfdntrlgscndnprspctv2009/lqfdntrlgscndnprspctv2009-eng.html

15 Natural gas reserves are defined as the total amount of marketable gas in discovered pools that can be extracted in current economic conditions.

FIGURE 5.6

Canadian Natural Gas Consumption and Heating Degree Days



(a) Estimates

(b) Heating degree days (HDD) is an index calculated to reflect the demand for energy needed for heating homes, businesses, etc. HDD is the cumulative number of degrees in a year for which the mean temperature falls below 18.3 degrees C.

Sources: Statistics Canada, NEB Estimates and Canadian Gas Association

5.4 Canadian Natural Gas Consumption

Approximately one quarter of all energy consumed by Canadians is natural gas. In 2009 estimated consumption was about 223 million m^3/d (7.8 Bcf/d) or about 54 per cent of Canadian production.

Natural gas is consumed in the residential and commercial sectors for space heating, and in the industrial sector for process heat. It is also used as a building block in chemical production, as well as to produce electricity. Canadian gas consumption for heating, industrial use and electric power generation (included within "direct sales") has been fairly constant since 2000 (Figure 5.6).

As for other forms of energy, 2009 saw an overall decrease (one per cent) in Canadian gas consumption due to less industrial activity across North America. Contrary to this trend, lower natural gas prices and Ontario's ongoing coal phase-out plan contributed to an increase in gas use for power generation in that province for the January to October 2009 period as compared to year-earlier levels.

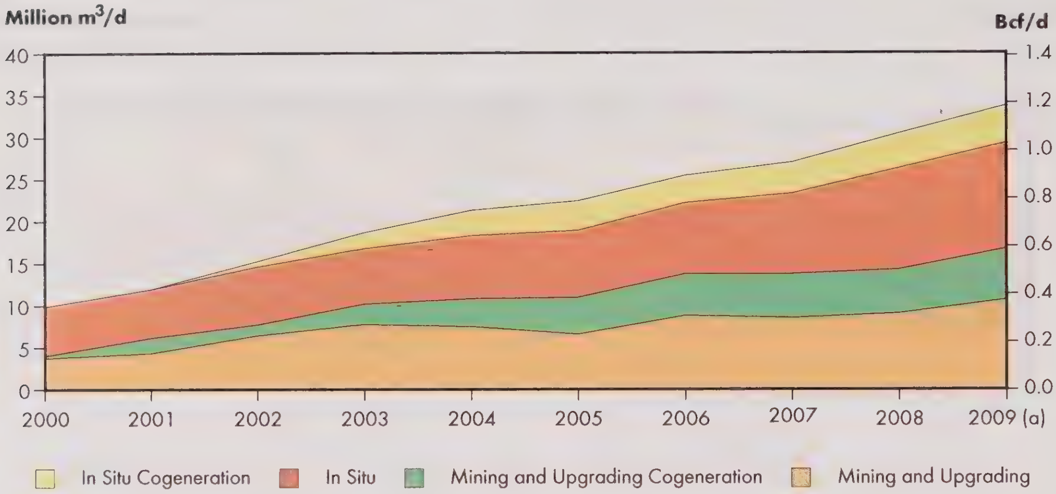
Natural gas consumption in the Alberta oil sands sector continued its decade-long rise in 2009 (Figure 5.7). Natural gas is used in both the generation of electricity and steam. Steam is used for in situ oil production and in the production of hydrogen to upgrade bitumen into synthetic crude oil blends. Consumption of natural gas in 2009 was approximately 34 million m^3/d (1.2 Bcf/d), ten per cent higher than in 2008 and almost four times the amount of gas used a decade earlier.

5.5 Canadian Natural Gas Exports and Imports

In 2009, natural gas exports were about 252 million m^3/d (8.9 Bcf/d) or 14 per cent of estimated U.S. consumption (Figure 5.8). Although U.S. consumption of natural gas in 2009 is estimated to be only marginally lower than in 2008, increased U.S. production and higher LNG imports pushed Canadian gas exports to the U.S. down by ten per cent compared to the previous year, while imports were 30 per cent higher. Net exports (gross exports less imports) for 2009 were 196 million m^3/d (6.9 Bcf/d).

FIGURE 5.7

Average Annual Natural Gas Requirements for Oil Sands Operations

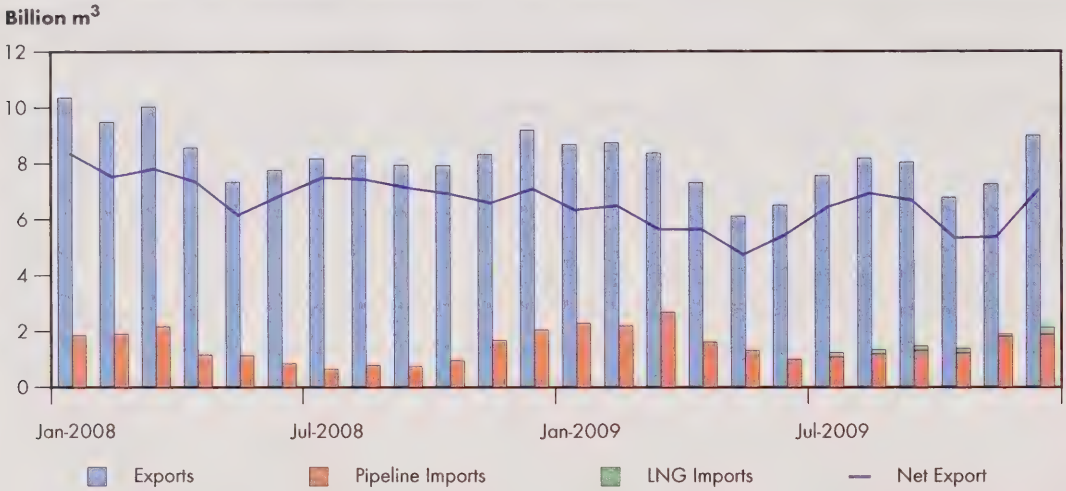


(a) Estimates

Sources: NEB and ERCB

FIGURE 5.8

Monthly Canadian Natural Gas Exports and Imports, 2008-2009

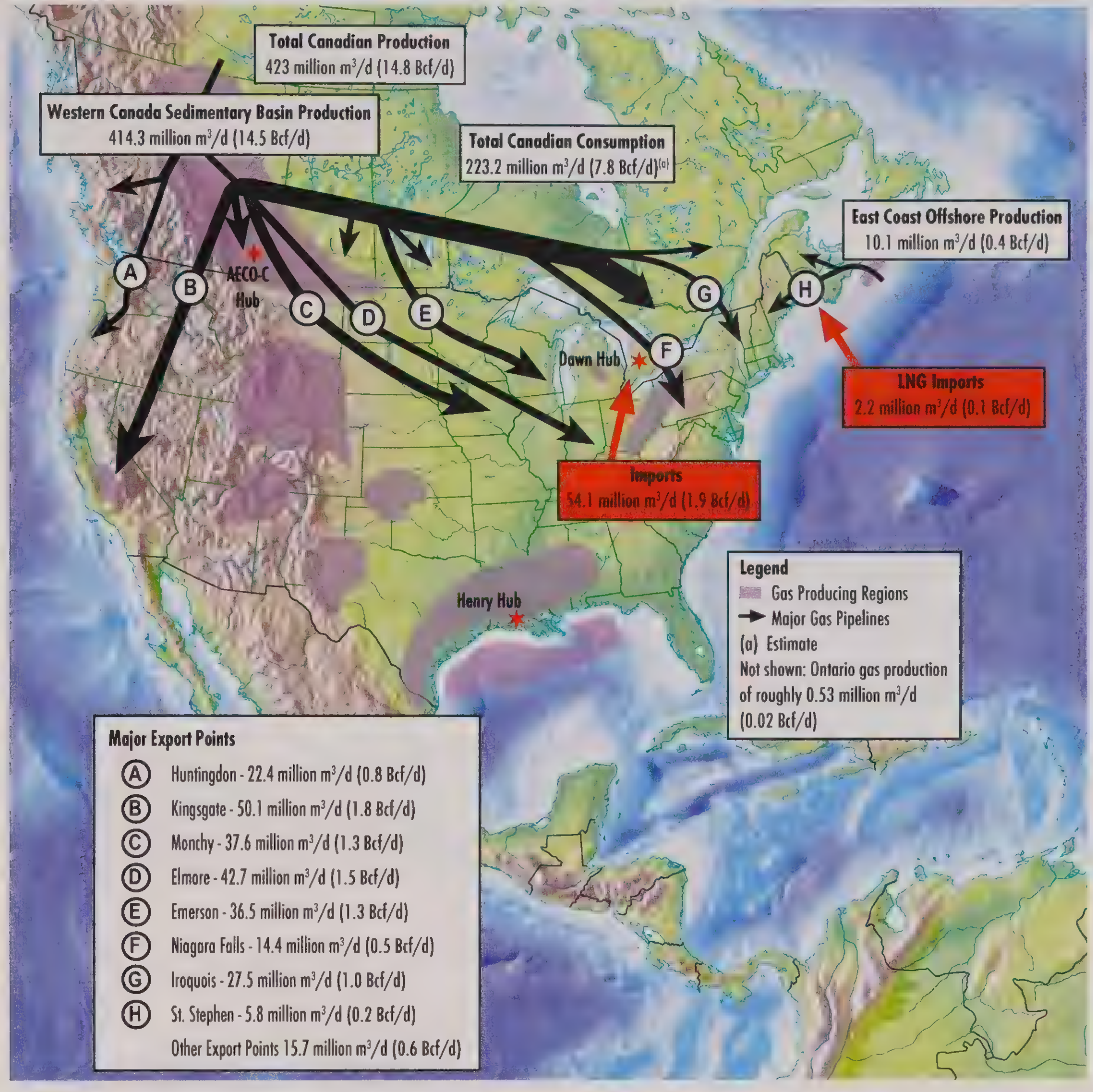


Source: NEB

Annual revenues from Canadian gas exports also dropped in 2009 because of lower commodity prices and lower export volumes. The average export price in 2009 was less than half of the average export price in 2008 resulting in net export revenues of only about \$11.9 billion in 2009, compared to \$27.9 billion in 2008.

FIGURE 5.9

Natural Gas Supply and Disposition, 2009



5.6 Natural Gas Liquids (excluding Pentanes Plus)

Prices for propane and butane rose in the latter half of 2009 because of the return of demand from the petrochemical sector in North America. Propane prices at Mont Belvieu, Texas the main NGL trading hub in the U.S., rose from a monthly average of 80.7 US cents per gallon in January 2009 to 125.8 US cents per gallon in December 2009. The average annual propane price at Mont Belvieu for 2009 was 89.1 US cents per gallon.

Canadian propane production in 2009 decreased by 7.0 per cent over 2008. Propane production from gas plants in 2009 was 24 597 m3/d (154.7 Mb/d), while production from refineries rose 8.5 per cent to 3 765 m3/d (23.7 Mb/d).

Butane production in Canada in 2009 was 22 688 m3/d (142.7 Mb/d), virtually unchanged from 2008 figures. Higher butane production from refineries (increase of 12.8 per cent from 2008) made up for

lower butane production from gas plants (decrease of 7.8 per cent from 2008). Refinery production of butane was 8 664 m3/d (54.5 Mb/d), while butane production from gas plants was 14 024 m3/d (88.2 Mb/d).

Canadian production of ethane from gas plants in 2009 was 38 338 m3/d (241.1 Mb/d), a decline of 1.2 per cent from 2008 production. Declining domestic natural gas production has reduced the amount of natural gas available for liquids extraction and is partly responsible for declining liquids production. Weak economic conditions in the first half of 2009 depressed demand for petrochemical feedstocks, such as ethane.

Propane exports in 2009 were 15 817 m3/d (99.5 Mb/d), declining 9.9 per cent from 2008. Exports of butane in 2009 were 4 509 m3/d (28.4 Mb/d), an increase of 7.6 per cent over last year. Propane exports declined due to lower production and economic conditions in the U.S. which reduced demand. Exports of butane have declined since 2002, but the trend reversed direction starting in 2008. PADD II (Midwest) remains the largest market for propane and butane exports, followed by PADD I (East Coast).

For propane, the impact of lower prices and lower export volumes in 2009 was significant: revenues were 36 per cent lower than 2008 at $1.5 billion. Compared to 2008, lower butane prices resulted in a 21.5 per cent decline in 2009 butane export revenues, which were to be $555 million. The increase in export volumes of butane mitigated the decline in butane export revenues.

5.7 Looking Ahead

Because natural gas prices are expected to rise from their 2009 lows in 2010, drilling activity in western Canada could also rise. However, natural gas-related activity is expected to remain relatively low compared to historical levels and Canadian production of natural gas will likely continue to fall in the short term.[16] In 2009 there were advances in Canadian shale gas development and evaluation and this trend is likely to continue throughout 2010.

The expectation of increasing use of natural gas for gas-fired power generation in Ontario could potentially result in increased imports of natural gas from U.S. pipeline infrastructure to deliver into the eastern Canadian transportation hub. Gas supply delivered to the hub located near Dawn, Ontario, has become increasingly diverse in recent years, accessing gas from growing shale gas supplies in the U.S.

16 National Energy Board. *Short-term Natural Gas Deliverability 2010-2012*, March 2010. Available at http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/ntrlgsdlvrblty20102012/ntrlgsdlvrblty20102012-eng.html.

ELECTRICITY

6.1 Regional Initiatives

Canadian electricity markets significantly differ from other energy markets as they are generally shaped by provincial government policies. In 2009 many regional initiatives focused on policies and programs to achieve set objectives. A number of these regional initiatives are discussed below.

> ***Key Findings:***
>
> - On the supply-side continued attention to renewable generation and reliable infrastructure
> - On the demand-side, there was continued emphasis on conservation and efficiency improvements
> - Generation from hydroelectric, nuclear and thermal sources was lower because of the economic downturn
> - Electricity consumption continued its decline in 2009
> - Electricity prices remained relatively stable during the year
> - Lower prices for natural gas reduced generation costs in the provinces that rely on natural gas for power generation

Western Canada

In the fall of 2009, British Columbia's Minister of Energy, Mines and Petroleum Resources announced that BC Hydro will no longer use the 50-year old natural gas-fired Burrard Thermal Generating Facility to meet the Province's firm energy needs. Consistent with the government's Climate Action Plan, the BC Energy Plan, and the *Utilities Commission Act*, this decision allows BC Hydro to continue acquiring cost-effective, clean and renewable power.

During 2009, BC Hydro launched the second phase of its two-phase "Bioenergy Call for Power" to provide the province with additional sources of clean electricity, while diversifying rural economies heavily based on the forest industry. Phase Two has a two-stream call process, one for larger-scale projects and the other for community-level electricity supply solutions.

The Province of Alberta passed the *Electric Statutes Amendment Act, 2009* (formerly Bill 50), eliminating the "needs hearing" for four transmission infrastructure projects deemed to be "critical" by the Alberta government.

SaskPower's supply strategy included the introduction of a Demand Response Program as a cost-effective option to ensure that its power system supports Saskatchewan's current and future economic growth. Qualified industrial customers will have the option to reduce or shift their electricity use when requested by SaskPower if, for example, the province is experiencing high demand or system constraints. A Demand Response Program increases operational flexibility and delays the need for construction of additional generation facilities and transmission lines.

The Government of Manitoba introduced proposed legislation, *Manitoba Hydro Amendment and Public Utilities Board Amendment Act* (Bill 20) that gives it the ability to adopt and regulate mandatory North American standards for generating and transmitting electricity in Manitoba.

Ontario

The *Green Energy Act* (GEA) was passed in spring 2009 to accelerate development of renewable generation and drive the expansion of transmission and distribution systems. The GEA enabled the launch of the Feed In Tariff (FIT) and microFIT programs in fall 2009 which solicit renewable generation project proposals from a variety of producers including homeowners, businesses, independent power producers, local distribution companies, and communities. Both programs have local content requirements designed to create green industries in Ontario. Projects are expected to create 20 000 jobs and enable development of green energy in areas otherwise inaccessible to the grid.

Quebec and Atlantic Canada

The Quebec government announced its policy to reduce GHG emissions by 20 per cent below 1990 levels by 2020. The initiatives to implement this policy will largely focus on the transportation industry, which contributes up to 40 per cent of the province's emissions. The government committed to implementing a cap and trade system by 2012 and is committed to the development of renewable energy sources, such as wind and hydro with the synergies to be explored between the two resources.

The Nova Scotia government launched its *2009 Energy Strategy* in January. The strategy legislates that by 2020, the province will reduce GHGs to at least ten per cent below 1990 levels. The electricity sector is the province's largest contributor, accounting for 50 per cent of GHG emissions. To reduce the electricity sector's carbon footprint, the government focused on two key elements: increase conservation and efficiency by 20 per cent by 2020 and obtain 25 per cent total electricity supply from low-impact renewable sources by 2015 through Renewable Energy Standards (RES).

Territories

In 2009, the Yukon government released its *Energy Strategy for Yukon*. The Report identified two central electricity targets to achieve by 2020: a 20 per cent increase in efficiency and a 20 per cent increase in renewable supply. Also, the Minister of Energy, Mines and Resources announced that Yukon is developing policies to foster development of renewable energy sources. The policies will focus on independent power production and net metering.

Renewable Energy Standards (RES)

Renewable Energy Standards require load-serving entities to source a percentage of their energy supply from renewable resources by a specified target year. Establishing RES is often seen as one of the stronger options policy makers have in addressing climate change issues by decreasing the electricity industry's overall emissions.

The structures of these standards vary greatly between provinces/states. They tend to promote the use of locally available clean or renewable resources. In areas where coal is abundant, RES might include "alternative energy" such as waste coal or coal gasification. Those with abundant hydro-electricity are inclined to include hydro in their criteria for clean and renewable energy. Harmonizing definitions across jurisdictions is difficult.

As of 2009, three provinces (NS, NB, PEI) and 30 states (including the District of Columbia) have RES in place, whereas seven provinces (BC, AB, SK, MB, ON, QC, NF) and six states have other targets and goals.

6.2 Electricity Prices

Canadian electricity prices are determined in regional markets. Prices in most jurisdictions are regulated and based on the cost of providing service to consumers including a regulated rate of return on generation, transmission and distribution assets. Costs are approved by provincial and, in some cases, municipal regulators. When required, the cost of new generation, usually higher than costs of "heritage assets,"[17] must also be approved and rolled in, resulting in higher average costs. This model is followed in all provinces and territories except Alberta, where generation costs are based on competitive wholesale markets. Ontario is a hybrid of the two methodologies, with a blend of heritage pricing for coal, nuclear and hydro plants and market-based pricing for new generation.

Figure 6.1 shows the monthly average prices in the Alberta and Ontario wholesale markets over the past two years. Due to adequate supply and decreased demand, the level and volatility of these prices were lower in 2009.

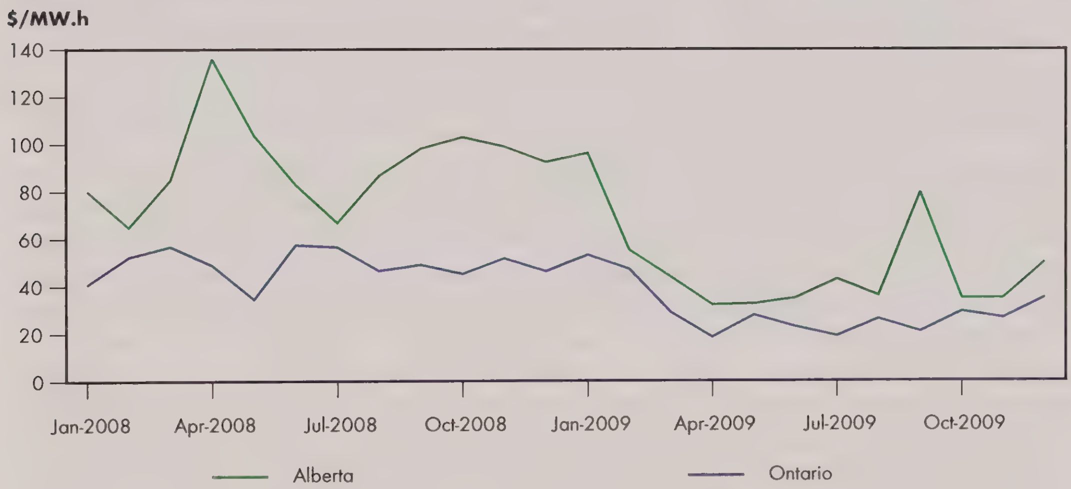
Prices tend to be lowest in hydro-based provinces such as British Columbia, Manitoba, and Quebec, which benefit from a high proportion of low-cost heritage assets, such as hydro-generating facilities that have minimal fuel costs and largely amortized capital costs. Electricity prices are most volatile in Canadian jurisdictions that rely on fossil fuels for generation, and are increasing most in those areas that require costly new generation and transmission.

Figure 6.2 charts the year-over-year average cost of electricity for a typical household in various Canadian cities based on rates in effect as of 1 April 2008 and 1 April 2009.

Residents in Alberta have the option to pay either a competitive contract rate, or the default Regulated Rate Option (RRO) which is set monthly. For the last four years, the RRO has been increasingly based on the next-month projected cost of electricity and less on the long-term projection. As of July 2010, it will be based entirely on the short-term cost. The difference in Edmonton's RRO from

FIGURE 6.1

Monthly Average Wholesale Electricity Market Prices – Alberta and Ontario



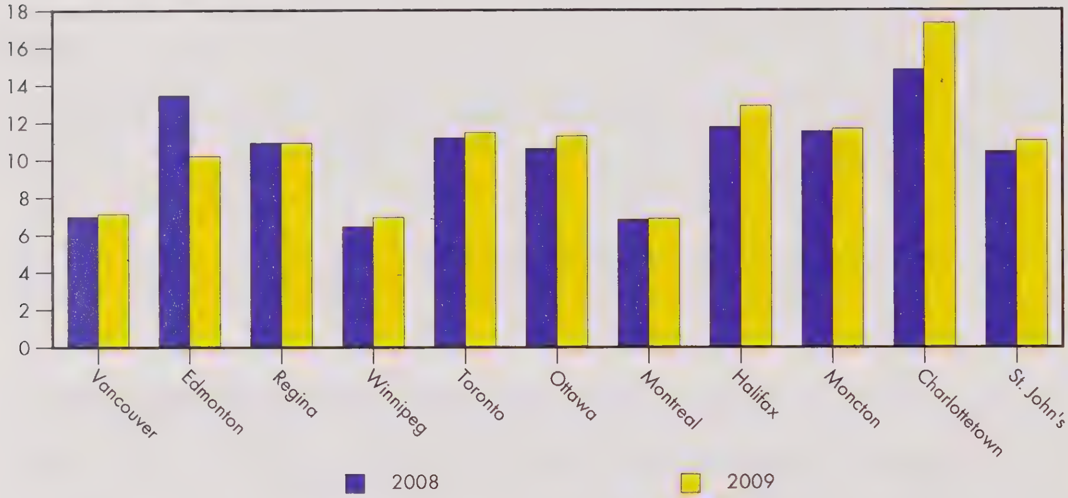
Sources: Alberta Electric System Operator, Independent Electric System Operator of Ontario

17 An amount of energy and capacity determined by the existing generation assets that resulted from past decisions under a previous market regime. This energy is generally sold into the marketplace at a price reflecting historical costs.

FIGURE 6.2

Canadian Residential Electricity Prices

Cents (Cdn) per kW.h



Source: Hydro-Québec, based on 1 April rates and a consumption level of 1 000 kW.h per month

April 2008 (9.7 cents/kW.h) to April 2009 (7.2 cents/kW.h) represents most of the decrease shown for Edmonton prices.

The cost of electricity for residents in PEI has risen in recent years due to increased commodity prices, decreased availability of lower cost generation, and changes to rate structures and use of deferral accounts.

6.3 Electric Reliability

Reliable operation of the Bulk Power System (BPS) requires both an adequate supply of generation and reliable operation of generation and transmission facilities despite power system disturbances and contingencies. Reliability standards are an important tool in ensuring that the BPS meets this goal.

Reliability standards developed by the North American Electric Reliability Corporation (NERC) and/or by NERC's regional reliability organizations are mandatory in the U.S. In Canada, the individual provinces are adopting either the NERC standards or compatible standards. For instance, NERC standards were adopted through legislation in British Columbia and Alberta. Similar legislation in Manitoba has been passed and is expected to be proclaimed in 2010. NERC standards are mandatory in Ontario and New Brunswick through the market rules governing transmission in those provinces. NERC standards are applicable in Saskatchewan through contractual agreements with the Midwest Reliability Organization (NERC's regional reliability organization). In Quebec, reliability standards are developed by TransÉnergie and approved by la Régie de l'énergie, the provincial energy regulator. In an effort to increase awareness, NERC has begun publishing reliability indicators on its web site. Some parties suggest that the effects of mandatory reliability standards are reflected in the absence of outages due to poor vegetation management[18] from July to September 2009, the first such absence in six years.

18 Trimming or removing vegetation, such as trees, surrounding electric power lines that can potentially create a serious public safety hazard or cause interruptions to electrical services.

6.4 Electricity Generation

In 2009, Canadian electricity generation decreased by four per cent from 2008 (Table 6.1) largely due to decreased demand caused by the economic downturn. Hydroelectric generation was slightly lower reflecting the poor water conditions experienced over the summer in British Columbia. Thermal generation continued to decline and decreased ten per cent from 2008 levels. Coal-fired generation also decreased as a result of Ontario's goal to phase-out coal-based assets by 2014. Contributing to lower nuclear production is the continued outage for refurbishment of nuclear generators: Point Lepreau in New Brunswick and Bruce A Units 1 and 2 in Ontario. Wind and tidal production increased by 70 per cent from 2008 levels. However, wind generation only accounted for one percent of Canadian electricity production in 2009.

TABLE 6.1

Electricity Production (TW.h)

	2005	2006	2007	2008	2009
Hydroelectric	358.4	349.5	365.8	369.3	363.4
Nuclear	86.8	92.4	88.2	88.6	85.3
Thermal	157.3	147.7	149.6	139.1	124.7
Wind & Tidal	1.6	2.5	2.9	3.6	6.1
Total	**604.2**	**592**	**606.5**	**600.6**	**575.3**

Note: Wind generation for 2008-2009 estimated based on CanWEA data.

Sources: 2005 to 2009: Statistics Canada 57-202
2008-2009: CanWEA, Statistics Canada 127-0002

Even in the presence of increased government incentives, the current economic environment has made financing of new projects difficult and as a result, projects in some provinces have been deferred, downsized or cancelled. Some jurisdictions no longer need to build new generation or refurbish existing assets in the short-term. Nevertheless, generation projects continued to develop throughout Canada in 2009.

Hydro

Canadian hydroelectric jurisdictions continue to focus on small and large hydro developments and refurbishments. BC Hydro signed electricity purchase agreements for 19 small hydro[19] projects to be owned, built and operated by independent power producers. Hydro Québec is also investing in small hydro developments with 150 MW to be purchased from small hydroelectric generating stations.

The Joint Keeyask Development Agreement was signed in May 2009 to outline the partnership arrangements for First Nations' participation in development projects with Manitoba Hydro. In addition to new generation facilities, refurbishments to existing facilities are taking place in Manitoba, British Columbia and Quebec. These investments create efficiencies and extend the life of heritage assets in some cases by at least 30 years.

Natural Gas

New capacity of natural gas-fired generation is mostly attributed to new builds both in Ontario and Alberta where approximately a total of 2 350 MW came online in 2009. According to the Ontario Independent Electric System Operator (IESO), natural gas has surpassed coal and now represents 24 per cent of the province's supply mix.

19 Between 2 MW and 50 MW

Coal

In Canadian jurisdictions where coal is a significant part of the mix, such as Ontario, Alberta, Saskatchewan and Nova Scotia, the economics of phasing-out coal compared to investment in compliance technologies continues to be explored. Ontario Power Generation announced in 2009 that they will close four coal-fired generation plants by October 2010. Alberta is upgrading existing coal-fired plants with compliance technologies. With the assistance of funding from the federal and provincial governments, progress is being made with respect to Carbon Capture and Storage (CCS) projects. (See text box on the Swan Hills project.)

Alberta's Swan Hills In Situ Coal Gasification, Combined Cycle Power Plant and Carbon Capture and Storage Project

On 1 December 2009 the Alberta government announced that it had signed a letter of intent with Swan Hills Synfuels for $285 million in funding from the Carbon Capture and Storage Fund. This project combines in situ coal gasification, CO_2 capture and sequestration in nearby oilfields and the construction of a 300 MW combined cycle power plant to run on the synthetic gas (syngas) produced.

This project has several parts, including the production of syngas underground in a coal bed, facilities to separate out CO_2, a combined cycle power plant to produce electricity and an enhanced oil recovery project that will sequester the carbon dioxide. While all of these technologies have been used in the past, this is the first time in Canada that they will have been combined in one project.

In situ coal gasification involves pumping oxygen down 1 400 metres underground into a coal seam, where it combines with the coal and saline water, normally found at that depth, to produce syngas, a mixture of hydrogen, methane, carbon dioxide, and carbon monoxide.

Once the syngas is brought to the surface the carbon monoxide is reacted with water to produce carbon dioxide and additional hydrogen, and the CO_2 is separated out and sent to an enhanced oil recovery project, where it is injected underground to boost production of oil from older wells. Enhanced oil recovery using CO_2 is a mature technology, limited mainly by access to reliable supplies of carbon dioxide.

Separating CO_2 from the methane and hydrogen in this type of facility is much easier than capturing it from the exhaust of a coal fired power plant, both because there is a higher concentration of CO_2 and it is easier to separate CO_2 from light molecules like hydrogen or methane (found in syngas) than heavier molecules of nitrogen, which make up the majority of the exhaust stream of a coal fired power plant.

Once the CO_2 has been removed, the clean syngas will be sent to a 300 MW combined cycle power plant. A combined cycle power plant consists of one or more combustion turbines connected to generators and a heat recovery steam generator that uses the combustion turbine exhaust to make steam which is sent to a steam turbine connected to another generator. Natural gas combined cycle power plants are a mature technology, with high efficiency and the lowest emissions per mega-watt hour of electricity produced of any fossil fuel power plant. The combustion turbines in the Swan Hills project will have to be modified slightly to run on syngas instead of natural gas, but the presence of hydrogen in the syngas means the Swan Hills plant should produce about half the CO_2 of a comparable natural gas power plant, much of which will be captured, or a quarter of the CO_2 of a conventional coal plant of the same size.

Construction on this project is expected to begin in 2011, with it entering service in 2015.

Nuclear

New Brunswick's Point Lepreau nuclear plant is expected to return to service by February 2011 following refurbishment. In Ontario, the provincial government put plans on hold to build new nuclear facilities, although refurbishments to existing facilities are being considered. In late 2009 the Government of Canada issued an invitation for investor proposals to purchase the Atomic Energy of Canada Limited CANDU Reactor Division.

Wind and Other Renewables

As of 2009, Canada has wind development in every province with the addition of B.C.'s 102 MW Bear Mountain Wind Park. Canada's total installed wind capacity now exceeds 3 300 MW. Canadian wind power development projects were hindered in 2009 in several provinces due to financing difficulties.

Since 2007, approximately 10 900 MW (including wind) have been registered with Canada's ecoENERGY Renewable Power Fund. Of the total projects, 1 100 MW were expected to complete commissioning in 2009. Solar, biomass and hydro projects in Ontario and British Columbia represent approximately 260 MW of the expected commissioned projects in 2009, with wind accounting for the remaining new capacity. There were also additional biomass projects that were awarded through various requests for proposals in Nova Scotia, British Columbia, and Quebec. The end of 2009 also witnessed Canada's first solar farm (29 MW) near Napanee, Ontario becoming operational.

Wind Integration: Opportunities and Challenges

While wind power has a number of unique benefits, its intermittent nature presents a challenge in integrating large amounts into existing power systems. Wind may not always be available at the required location so cannot be relied upon for base-load requirements. Intermittent wind power therefore implies that another energy source must be available to alleviate the impact on electric system reliability. There are a number of measures that can mitigate wind intermittency concerns, including wind availability forecasting, a robust transmission system and synergy with other generation systems.

Advanced daily or hourly forecasts for wind speed and wind turbine generation are valuable, as this provides system operators with time to respond to changes. Of particular use to electric system operators is advanced notice of extremely high wind speeds to prevent damage to the equipment.

A robust transmission system can support the integration of wind generation by drawing on the generation resources of a neighbouring region. Denmark, which has little hydro generation, can still support over 20 per cent wind capacity because its transmission system connects it to hydro resources in Norway and Sweden.

Based on technical studies and experience in Europe and in the U.S., a predominantly thermal system is expected to be able to function normally with up to 10 per cent of its installed generating capacity being wind turbines, whereas a mainly hydro-based system could support up to 20 per cent installed wind capacity. With additional investment in transmission, control systems and back-up generation, installed capacity of wind generation can be increased to 15 per cent for predominantly thermal systems and 30 per cent for hydro systems.

Tidal Energy Generation

As of 2009 there are only three tidal power plants in the world that use first generation dam or barrage technology[1]. Nova Scotia Power's Annapolis Tidal Power has been operational since 1984 and employs this type of technology. Engineers have now developed in-stream tidal technology that uses the natural flow of tides. These turbines are attached to the ocean floor through a sub-sea gravity base and operate like an underwater windmill by using tide flow to turn an impeller. In-stream tidal turbines can connect to the grid for performance testing, safety monitoring and environmental assessments. In a study conducted by the Electric Power Research Institute, the Bay of Fundy was identified as an ideal location to deploy in-stream tidal technology. In November 2009 the Irish firm, OpenHydro, in partnership with Nova Scotia Power, launched the Bay of Fundy's first commercial scale 1 MW in-stream turbine.

This technology and industry are still in the infancy stage and over the next few years it will be important to monitor the impact of ice on the turbines and address underwater site challenges. Advocates argue that of all the renewable energy technologies, tidal power is the most predictable, reliable and dispatchable. Both the Government of Canada and Nova Scotia are in support of the new technology and the potential for a new marine energy industry. OpenHydro and Nova Scotia Power received $9 million from the province for research and development costs.

Source: Electric Power Research Institute, Ocean Tidal and Wave Energy - Renewable Energy Technical Assessment Guide - TAD-RE: 2005 Product ID: 1010489

1 Barrages are basically dams across the full width of a river where it empties into another body of water, in this case, the Bay of Fundy. Barrages make use of the potential energy between high and low tides.

6.5 Electricity Demand

In 2009, electricity demand continued to decline, falling five per cent compared with 2008 levels (Table 6.2). Behind this story of reduced consumption is a mix of increased efficiency, conservation efforts, cooler summer weather and the slower economy's effects on power use. In particular, the economic downturn has significantly decreased industrial use of electricity in Ontario, where consumption decreased by ten per cent from 2008. However, factors that influence lower levels of electricity demand can sometimes be overpowered by extreme weather. For example, in December 2009, Alberta experienced severe cold weather; resulting in a record demand peak, much higher than had been forecasted for the 2009 winter season.

TABLE 6.2

Electricity Generation and Disposition (TW.h)

	2005	2006	2007	2008	2009
Supply					
Total Generation	604.2	592	606.5	600.6	575.3
Imports	18.7	22.1	18.4	23.5	18.3
Total Supply	**622.8**	**614.1**	**625**	**624.1**	**593.6**
Disposition					
Demand	580.5	574.3	575.6	568.4	540.3
Exports	42.3	39.7	49.3	55.7	53.3
Total Disposition	**622.8**	**614.1**	**625**	**624.1**	**593.6**

Sources: 2005 to 2009: Statistics Canada 57-202, NEB
2008-2009: CanWEA, Statistics Canada 127-0002, NEB

Jurisdictions that experienced decreases in electricity demand ranging from two to three per cent were PEI, New Brunswick, Saskatchewan, Alberta and British Columbia. New Brunswick generated lower levels of electricity and imported 34 per cent more energy from other provinces compared to 2008. Quebec, Nova Scotia, and Newfoundland and Labrador experienced a drop in electricity consumption of between four and five per cent. Ontario experienced the largest decline as a result of the impact of the economic recession on industries like pulp and paper, steel, mining and auto manufacturing. As a result, the province experienced frequent levels of surplus baseload generation, requiring the Ontario IESO to direct the shutdown of nuclear units. Manitoba experienced an increase of one per cent. Electricity consumption trends in the territories varied in comparison to 2008. Yukon's electricity use rose by 17 per cent, from, among other things, increased mining development. The Northwest Territories remained relatively stable at 2008 levels and Nunavut experienced an increase of three per cent.

6.6 Electricity Exports and Imports

Electricity exports decreased four per cent and imports decreased 22 per cent (Table 6.2). The result was a slight year-over-year increase in net exports to the United States. The value of electricity traded between Canada and the U.S. (the sum of export revenue and import costs) decreased by 41 per cent as a result of lower trade levels coupled with lower wholesale market prices.

Canadian electricity jurisdictions tend to be winter-peaking systems, and so the largest imports of electricity from the U.S. typically occur during the winter when local heating requirements are highest. The large hydro-electric capacity of some provinces (Quebec, B.C., Ontario and Manitoba) generally enables exporters to benefit by exporting when prices are high (in the middle of the day) and importing when prices are low (off-peak hours).

With the decrease in consumption, the supply margins in most provinces were high, and the need to import was significantly reduced. One exception to this was in the Maritimes, as the continued refurbishment of Point Lepreau contributed to increased imports during the winter months. Another

FIGURE 6.3

International and Interprovincial Transfers of Electricity, 2009 (GW.h)

contributing factor to decreased trade was the relatively low precipitation and reservoir levels in 2009. Following a year of abundant hydro resources, some provinces, B.C. in particular, increased imports.

6.7 Looking Ahead

The driver for investment in the industry now includes a focus on renewable energy programs. Renewable energy has been advocated through provincial and federal government policies with incentives to fund the development of sources such as hydro, wind, solar, biomass and efficiency technologies like smart grid and carbon capture and storage linked to coal fired generation. Regional projects and developments with an emphasis on sustainability continue to evolve, such as installing smart meters to enable and improve demand-side management, address efficiency and reliability concerns, and manage the growth of renewable energy.

Canadian electricity consumers, from residential to industrial, have a greater number of programs and incentives designed to aid in efficient energy consumption. Programs offer funds and resources to local governments, developers, and institutions to support informed choices about energy management and increased efficiency through planning, development and implementation of district energy systems.

Moving forward, participants in the electricity sector will continue to focus their efforts towards supply side management that incorporates renewable generation and ensuring reliable infrastructure as well as demand side management with conservation and efficiency improvement programs. Efforts in the U.S. to pursue sustainable energy options may well result in increased electricity trade as both countries seek to optimize their renewable resources and transmission interconnections.

Conclusion

In 2009 the economic downturn led to decreases in both the consumption and the production of energy in Canada. This impacted energy prices and reduced export volumes resulting in less Canadian energy export revenue. Despite this reduction, energy still contributed 22 per cent of the total Canadian export revenue in 2009. By year-end, there were signs that the economy was improving, and 2010 began with increased optimism that an economic recovery was underway.

Canadians remained interested in environmental issues. There were a number of announcements by governments at the federal and provincial levels to deal with sustainable development and environmental issues. The issue of climate change continued to have a high profile at the international level.

Per capita energy demand has declined by eight per cent over the last five years. However, while suggesting that Canadians are taking steps to reduce consumption, it is not always clear how much of reduced consumption is due to conservation and how much can be attributed to other factors such as weather and the economic slowdown.

The natural gas industry continued to evolve. There was a shift toward more prolific deep-basin tight gas in Alberta and Montney gas in northeastern B.C. As a result of low drilling activity, production and natural gas exports were down. The development of shale gas continued and the availability of LNG to North America increased in 2009 with the first receipt in Canada at Canaport. Total natural gas consumption was stable, but industrial consumption, with the exception of the oil sands, was lower than in previous years.

The average price for crude oil (Edmonton Par) was \$65/bbl in 2009, considerably lower than the \$102/bbl in 2008. Lower crude oil prices negatively impacted industry performance, including less land bonuses for oil sands leases and reduced value of crude oil exports and refined petroleum products. Lower crude oil prices had a positive impact, by lowering the cost of gasoline, diesel fuel and heating oil for consumers. The second half of the year featured a recovery in oil sands development. In spite of some minor shut-in of production, oil sands production grew based on the momentum established in previous years.

In 2009, electricity activity continued to focus on renewable generation and reliable infrastructure, as well as conservation programs. Generation from hydroelectric, nuclear and thermal sources was lower than in 2008. Wind production, although a small portion of total generation, continued its trend of strong growth. Electricity consumption continued its decline due to a mix of factors such as the economic downturn, cooler summer weather, increased efficiency and conservation. Prices for electricity remained generally stable with lower prices for natural gas reducing costs in those provinces that rely on natural gas for power generation.

Glossary

AECO/NIT price	Now known as the Intra-Alberta/NIT price. Historically, AECO was the name of a group of storage fields located in southeastern Alberta and operated by the Alberta Energy Company (now EnCana) and the Nova Inventory Transfer (NIT) is a title transfer service operated by TransCanada PipeLines Ltd.
Coalbed methane	Is a form of natural gas extracted from coalbeds. Coalbed methane, often referred to as CBM, is distinct from a typical sandstone or other conventional gas reservoir, as the methane is stored within the coal by a process called adsorption.
Condensate	A mixture comprised mainly of pentanes and heavier hydrocarbons recovered as a liquid from field separators, scrubbers or other gathering facilities or at the inlet of a natural gas processing plant before the gas is processed. Also known as natural gasoline.
Conventional natural gas	Conventional natural gas is gas contained in geological formations that is produced by expansion of the gas molecules into the well bore. In this report, it has a sub-category called tight gas that others may consider as unconventional natural gas. However, there is no agreed-upon regulatory definition accepted for use in Canada at this time, so it is kept as a sub-category of conventional gas.
Distillate	Fraction of crude oil; a general classification of fuels that includes heating oil, diesel fuel and kerosene.
Henry Hub	The biggest hub where the benchmark price is established for natural gas in North America. It is the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange. It is located in the state of Louisiana at the interconnection of numerous intra and interstate natural gas pipelines.
Hub	A geographic location where large numbers of buyers and sellers trade a commodity and where physical receipts and deliveries occur.
In situ recovery	Recovery techniques which apply heat or solvents to heavy oil or bitumen reservoirs beneath the earth.

Light-heavy differential	The price difference between heavy and light crude oil.
Natural Gas Liquids	Those hydrocarbon components recovered from natural gas as liquids. These liquids include, but are not limited to, ethane, propane, butanes and pentanes plus.
Oil sands	Sand and other rock material that contains bitumen. Each particle of oil sand is coated with a layer of water and a thin film of bitumen.
Pentanes plus	A mixture mainly of pentanes and heavier hydrocarbons obtained from the processing of raw gas, condensate or crude oil.
Spot price	The current delivery price of a commodity being traded on the spot market.
Thermal generation	Energy conversion in which fuel is consumed to generate heat energy which is converted to mechanical energy and then to electricity.